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January 4, 2007

BAW-2374-NP, Rev.2
Project Number 694

OG-07-3

U.S. Nuclear Regulatory Commission
Document Control Desk
Washington DC 20555-0001

Subject: Pressurized Water Reactor Owners Group
Submittal of BAW-2374-NP, Revision 2 "Risk-Informed Assessment of Once Through Steam Generator Tube Thermal Loads due to Breaks in Reactor Coolant System Upper Hot Leg Large-Bore Piping" (PA-ASC-0255)

The Pressurized Water Reactor Owners Group (PWROG) is requesting formal review of BAW-2374 Revision 2 in accordance with the Nuclear Regulatory Commission (NRC) licensing topical report program for review and acceptance for referencing in licensing actions. BAW-2374 Revision 2 is applicable to the ANO-1, CR-3, DB-1, and TMI-1 plants. Four copies of the report are being submitted with this letter.

BAW-2374 Revision 2 presents a technical justification to support a change to the licensing basis of Babcock & Wilcox designed nuclear power plants. The requested change to the licensing basis is to establish a risk-informed basis for the acceptability of postulated thermal loads on once-through steam generator (OTSG) tubes, tube repair products, and tube-to-tubesheet joints induced by a loss of coolant accident (LOCA) in the large-bore piping of the reactor coolant system in the hot leg piping. The justification for the change is that the maximum thermal loads from a break in the hot leg large bore piping, and the subsequent possibility of induced steam generator tube rupture, represent a very small risk per the probabilistic and deterministic guidance of Regulatory Guide 1.174.

The risk-informed evaluation presented in this report demonstrates the acceptability of thermal loads on OTSG tubes, tube repair products and tube-to-tubesheet joints from the most limiting break in the upper hot leg large-bore piping. Therefore, the acceptability of OTSG thermal loads will be based on this report, and on deterministic evaluation of the previously analyzed limiting accident, which is either a LOCA in RCS attached piping, (for example, the pressurizer surge line) or main steam line break (MSLB).

Consistent with the Office of Nuclear Reactor Regulation, Office Instruction LIC-500, "Processing Request for Reviews of Topical Reports," the PWROG requests that the NRC provide target dates for any Request(s) for Additional Information and for issuance of the Safety Evaluation for BAW-2374, Revision 2.

D048
Rec'd 2/1/07
DCD

Correspondence related to this transmittal and invoices associated with the review of BAW-2374, Revision 2 should be addressed to:

Mr. Gordon Bischoff
Program Manager, PMO Office
Westinghouse Electric Company
Energy Center
P. O. Box 355
Pittsburgh, PA 15230-0355

If you have any questions, please do not hesitate to contact me at (630) 657-3897, or if you require further information, please contact Mr. Paul Hijeck of the PWR Owners Group Project Management Office at (860) 731-6240.

Regards,

Paul Hijeck for

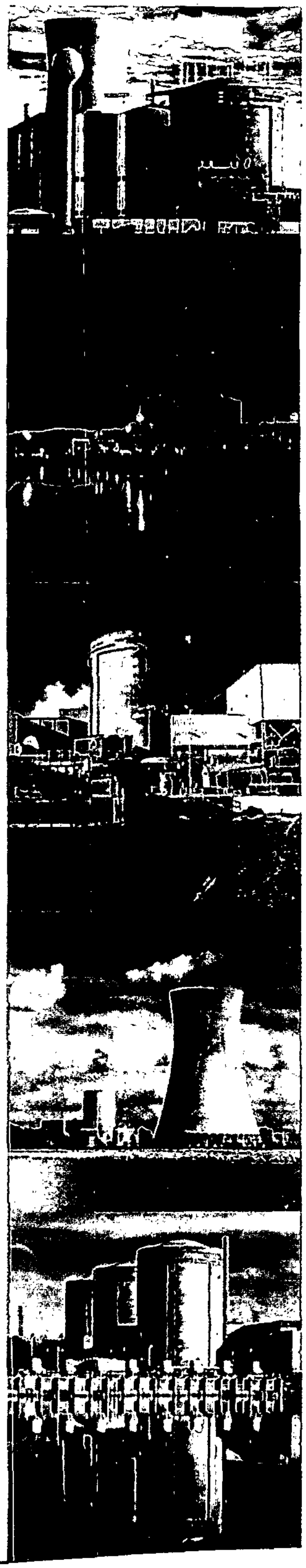
Frederick P. "Ted" Schiffley, II, Chairman
PWR Owners Group

FPS:PJH:las

Enclosures (4)

cc: S. Peters, USNRC
R. Schomaker, AREVA NP

BAW-2374 Revision 2
December 2006



Risk-Informed Assessment of Once-Through Steam Generator Tube Thermal Loads due to Breaks in Reactor Coolant System Upper Hot Leg Large-Bore Piping

PWROG
PWR Owners Group

Prepared for
B&W Plants in the PWR Owners Group
By
AREVA NP

AREVA

BAW-2374 Rev. 2
Topical Report
December 2006

Risk-Informed Assessment of Once-Through Steam Generator Tube Thermal Loads due to Breaks in Reactor Coolant System Upper Hot Leg Large-Bore Piping

Prepared for the
B&W Plants in the PWR Owners Group

by
AREVA NP
Lynchburg, Virginia

Note: The work effort for this Topical Report spanned roughly eight years and its historical perspective covers the entire operating history for the B&W-designed plants. The names and participation of some of the utilities, Owners Groups, and vendors have changed during this time interval. The text refers in places to the previous entities such as the B&WOG (B&W Owners Group), which is now the B&W-plant owners who make up a subset of the PWR Owners Group (PWROG). AREVA NP was previously referred to as B&W or Framatome ANP in the Topical Report. In many portions of the report, the historical names have been preserved in Revision 2 of BAW-2374.

The margin bars denote changes from Revision 1

Executive Summary

This Topical Report presents a technical justification to support a change to the licensing basis of Babcock & Wilcox-designed nuclear power plants. The requested change to the licensing basis is to establish a risk-informed basis for the acceptability of postulated thermal loads on once-through steam generator (OTSG) tubes, tube repair products, and tube-to-tubesheet joints induced by a loss of coolant accident (LOCA) in the large-bore piping of the reactor coolant system (RCS) in the hot leg piping. The justification for the requested change is that the maximum thermal loads from a break in the hot leg large-bore piping, and the subsequent possibility of induced steam generator tube rupture, represent a very small risk per the probabilistic and deterministic guidance of Regulatory Guide (RG) 1.174. The risk-informed evaluation presented in this report demonstrates the acceptability of thermal loads on OTSG tubes, tube repair products and tube-to-tubesheet joints from the most limiting break in the upper hot leg large-bore piping. Therefore, the acceptability of OTSG thermal loads will be based on this report, and on deterministic evaluation of the previously analyzed limiting accident, which is either a LOCA in RCS attached piping (for example, the pressurizer surge line) or main steam line break (MSLB).

In 1985, the B&W Owners Group (B&WOG) issued Topical Report BAW-1847, which presented the technical basis for application of leak-before-break (LBB) technology to the large-bore piping of the B&W plants. In the late-1980s, the B&WOG initiated a plan to update the analyses supporting the OTSG tube repair criteria. This analysis was performed to address flaw morphologies that had not been considered in the earlier work. During this effort, a large-bore RCS pipe break was not considered a credible event based on the work done in support of LBB. As a result, all OTSG tube repair hardware and processes developed after 1990 were qualified without consideration of large-bore RCS pipe break conditions. The main steam line break MSLB and RCS attached pipe break transients were used as the limiting accident condition loading for all tube repair hardware.

In the spring of 2000, the B&WOG became aware that the NRC did not agree with the use of the leak-before-break methodology as the basis for the 1990 decision to not include the thermal loads following a large-bore pipe break as a design condition for OTSG tubes. This initiated a review to determine the most appropriate way to address the potential consequences of a large-bore pipe break on the OTSG tubes. The review included a determination of the RCS locations where a large-bore pipe break could theoretically produce more limiting tube loads than those previously considered. This review concluded that the RCS refill phase following a LOCA in the hot leg U-bend, otherwise known as the "candy cane" region, could result in increased tube loads because of the large tube-to-shell temperature difference that may be established. Because the event was determined to have a low risk, Framatome ANP and the B&WOG developed a risk-informed technical basis to address the potential tube loads from upper hot leg large-bore pipe breaks. This Topical Report provides that technical basis and the corresponding proposed change to the licensing basis.

This Topical Report supports the licensing basis for the existing OTSG tube repair hardware and maintenance practices, and will be referenced in the licensing basis of future repair products, maintenance practices, and replacement OTSGs. There will be no relaxation of the actual design, testing, inspection, plugging/repair criteria, physical and material properties, and integrity programs of the OTSGs as a result of approval of the requested licensing basis change, because these specific thermal loads have not previously been included as a faulted design condition for the OTSG tubes.

This change to the OTSG licensing basis reduces the potential for premature plugging of steam generator tubes. If the acceptability of OTSG thermal loads was based upon the upper hot leg large-bore pipe break, the limiting loads and resulting tubesheet bore dilations would result in additional restrictions for tube repair products. This would require additional tube plugging. These consequences would be excessively burdensome and unnecessary, considering that the likelihood of the postulated upper hot leg large-bore pipe break is very small, and the consequences of the resulting thermal loads on the steam generator (possible LOCA-induced steam generator tube rupture) are not risk-significant and all 10 CFR 50.46 and 10 CFR 100 or 50.67 criteria are met.

This Topical Report was prepared following the guidance of Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis." In accordance with the guidelines of RG 1.174, the key principles for risk-informed decision-making have been met. These principles span both traditional deterministic and risk analysis methods.

A bounding risk analysis has been performed to estimate the potential risk contribution from possible loss of OTSG tube integrity due to tube loads induced by large-bore RCS pipe break. These estimates of the change in core damage frequency (ΔCDF) and change in large early release frequency (ΔLERF) represent the risk impact of the proposed licensing basis change, for comparison to RG 1.174 criteria. Probabilistic Risk Assessment (PRA) sequences have been developed that model LOCA-induced steam generator tube rupture due to breaks in large-bore RCS piping. The LOCA of concern is a break in the upper hot leg large-bore piping. The emergency core cooling system (ECCS) refills the RCS including the hot leg and OTSG tube regions of the broken loop, and a continuous liquid flow through the OTSG tubes and out the break is established. This liquid throughput can eventually result in a large broken loop tube-to-shell temperature difference, which is assumed in the PRA sequences to induce gross (multiple tube) steam generator tube rupture (SGTR). Significant primary-to-secondary OTSG leakage is assumed for these PRA sequences so that the risk estimate will bound any realistic uncertainty associated with OTSG tube integrity. This is a conservative assumption. The risk analysis includes the possibility of a secondary side isolation failure, which is required for the induced SGTR to be of consequence with respect to CDF and LERF. The isolation failure leads to the eventual depletion of reactor building (RB) sump inventory through the secondary side causing late core damage. The LOCA-induced SGTR may also contribute to large early release if early core damage occurs due to independent means. Even with the conservative assumption that significant OTSG tube failure is a certainty, the ΔCDF is less than 8×10^{-10}/year, and the ΔLERF is less than 4 x 10^{-11}/year. Relative to the acceptance guidelines in RG 1.174, this is considered a "very small" risk increase. The realistic probability of multiple free span tube severs is determined in Appendix E. If these probabilities were used, then the risk increase is even smaller as demonstrated by the PRA sensitivity study in Section 3.4.10.

The proposed licensing basis change is consistent with the defense-in-depth philosophy as discussed in RG 1.174. The balance between prevention of core damage and prevention of containment failure/consequence mitigation is not affected by consideration of OTSG tube loads induced by large-bore RCS pipe break, and independence of defense-in-depth barriers is not degraded.

The proposed licensing basis change maintains sufficient safety margins. For the limited condition of the RCS upper hot leg break location, there is a potential compromise of steam generator tube safety margin because, for this specific location, the OTSG thermal loads may be greater than for the previously analyzed limiting LOCA, which is the RCS attached pipe break. This is acceptable because the risk to public health and safety is "very small" according to the guidelines of RG 1.174 as demonstrated by minimal changes in core damage frequency and large early release frequency, and the maintenance of defense-in-depth principles. While the consequence of a hot leg break is considered alternatively without explicit consideration in the steam generator mechanical aspects[1], it must be considered with respect to 10 CFR 50.46 and 10 CFR 100 or 10 CFR 50.67. Compliance with the long-term cooling criteria of 50.46 and the dose criteria of part 100 or 50.67 is demonstrated for all primary-to-secondary tube leakage up to that calculated for four severed tubes in the free span region of the steam generator. Licensing Commitments or Technical Specification commitments to perform operability assessments following steam generator inspections confirms that leakage greater than the equivalent of four severed tubes is not credible. For all other design basis accidents, the 1 gpm leakage criteria is retained and the OTSG structural safety margins are unaffected by

[1] The Steam Generator mechanical aspects were defined earlier as tubes, tube repair products, and tube-to-tubesheet joints.

the requested change, and the tubes, tube repair products, and tube-to-tubesheet joints will continue to meet all existing regulations and requirements. In the current OTSG licensing basis, the limiting accident conditions are RCS attached pipe breaks and MSLB. With approval of this Topical Report, the limiting accident conditions will remain the same, i.e., RCS attached pipe breaks and MSLB. The existing safety analysis ensures that the limiting events, considering risk significance, have been evaluated, and that current safety margins are maintained.

Each B&W-designed plant has performance monitoring programs to ensure that no adverse degradation occurs because of the proposed change to the licensing basis, and that the performance of the systems, structures and components (SSCs) that are relied upon to justify the proposed change will be maintained. Existing plant programs, such as the Maintenance Rule Program and the Steam Generator Program, ensure that any unanticipated degradation of performance related to the proposed licensing basis change will be identified early and corrected.

This Topical Report presents the technical justification for changing the licensing basis of B&W-designed nuclear power plants. This requested change is to establish a risk-informed basis for acceptability of OTSG thermal loads from an upper hot leg large-bore pipe break. The basis for the proposed licensing basis change has been prepared in accordance with the deterministic and probabilistic guidance of Regulatory Guide 1.174. This Topical Report has demonstrated that the proposed change to the licensing basis will not adversely impact risk to public health and safety, and that NRC approval is justified.

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Table of Contents

List of Tables

List of Figures

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1.0 Introduction

1.1 Objective

This Topical Report presents a technical justification to support a change to the licensing basis of Babcock & Wilcox-designed nuclear power plants. The requested change to the licensing basis is to establish a risk-informed basis for acceptability of postulated thermal loads on once-through steam generator (OTSG) tubes, tube repair products and tube-to-tubesheet joints induced by a loss of coolant accident (LOCA) in the hot leg of the large-bore reactor coolant system (RCS) piping. The basis for the requested change is that the thermal loads from the specific RCS break, and the subsequent possibility of induced steam generator tube rupture, represent a very small risk as evaluated per the probabilistic and deterministic guidance of Regulatory Guide 1.174 (RG 1.174) [1]. The risk-informed evaluation presented in this report demonstrates the acceptability of thermal loads on OTSG tubes, tube repair products and tube-to-tubesheet joints from a break in the upper hot leg large-bore piping. Therefore, the acceptability of OTSG thermal loads will be based on this report, and on deterministic evaluation of the previously analyzed limiting accident, which is either a LOCA in RCS attached piping (for example, the pressurizer surge line) or main steam line break (MSLB). If approved by the NRC, each affected licensee may make appropriate changes or references to their Safety Analysis Reports, and licensing and design basis documents, as necessary, to incorporate the change into the plant's licensing basis.

1.2 Background

The original licensing basis of the B&W Nuclear Steam Supply System included consideration for the effects of large break loss-of-coolant accidents (LBLOCA). The reactor vessel exit (hot leg) nozzle LBLOCA is included as a faulted condition in the

Reactor Coolant System Functional Specifications for the individual plants. Topical Report BAW-10027 [2] documented the dynamic loading analysis and testing that was performed to quantify the effects of the LBLOCA on the OTSG. Topical Report BAW-10027 concluded that neither tube failure nor tube-to-tubesheet joint failure was experienced as a result of the primary blowdown structural tests. Topical Report BAW-10027 also contained results of other faulted condition events (including MSLB), as well as results from normal and operating condition tests. Operating Licenses were issued to the B&W-designed nuclear power plants by the NRC based upon results of Topical Report BAW-10027.

In the late 1970s, the B&W Owners Group (B&WOG) initiated an analysis program to more rigorously define steam generator tube repair criteria in accordance with the guidance of the Nuclear Regulatory Commission (NRC) Draft Regulatory Guide 1.121 [3]. This analysis addressed tube support plate wear-type degradation, which was the only significant degradation present in the OTSGs at that time. The results were documented in Topical Report BAW-10146 [4], which was submitted to the NRC in 1980. The NRC did not issue an evaluation report to the B&WOG regarding Topical Report BAW-10146.

In the analysis for Topical Report BAW-10146, thermally-induced loads on the OTSG tubes were considered for a number of normal operation, upset, and faulted conditions. These loads result from the differential thermal expansion between the OTSG tubes and the shell, which is rigidly attached to the tubesheets at both ends (see Figure 1-1). Faulted condition tube loads were calculated for both a MSLB and the reactor vessel exit nozzle LBLOCA event. At the time, the MSLB was predicted to produce the limiting faulted condition load (3140 lbs. tension). Due to their magnitude, thermal tube loads associated with the MSLB accident condition were considered in OTSG tube repair criteria analysis.

In 1985, the B&WOG issued Topical Report BAW-1847 [5][6], which presented the technical basis for application of leak-before-break (LBB) technology to the large-bore piping of the B&W plants. This Topical Report was used as a basis for meeting the exception criteria of General Design Criteria 4 (GDC-4). GDC-4 allows the dynamic effects of large-bore pipe breaks to be excluded from the licensing basis when analyses, reviewed and approved by the NRC, demonstrate that the probability of fluid system piping rupture is extremely low. LBB was used, with the NRC's approval, to justify removal of certain piping restraints and supports at the plants.

Also in the late-1980s, the B&WOG initiated a plan to update the analyses supporting the OTSG tube repair criteria originally documented in BAW-10146. This analysis was performed to address flaw morphologies that had not been considered in the earlier work. During the first task of this plan, analyses were performed to re-evaluate the limiting accident condition tube loads. The analyses for the MSLB were updated and new loads were developed, which resulted in a decrease in the predicted loads for all plants. During this effort, a large-bore RCS pipe break was not considered a credible event based on the work done in support of LBB, and therefore associated thermal loads were not included as a faulted design condition for the tubes.

As a result, all OTSG tube repair hardware and processes developed after 1990 were qualified without consideration of large-bore pipe break conditions. Until about 1998, the MSLB transient was used as the limiting accident condition loading for all tube repair hardware. In 1998, LOCAs of RCS attached pipes were identified as having the potential to present a limiting accident condition loading (identified in Preliminary Safety Concern 2-98). Tubes and repair hardware were re-evaluated to address the effects of the RCS attached pipe LOCA, which falls into the small break loss of coolant accident (SBLOCA) category. Depending on the particular repair product and the plant for which it was being applied, the limiting accident condition is now either the MSLB or LOCA of an attached pipe. The largest attached pipes include the pressurizer surge line, decay heat drop line, and core flood tank line. The pressurizer surge line is the limiting attached pipe break for generating the OTSG tube-to-shell differential temperature for the 177-FA Lower Loop plants. The Davis-Besse 177-FA Raised Loop plant uses the limiting thermal loads from the pressurizer surge line break or the continuous upper head vent line break.

In the spring of 2000, the B&WOG became aware that the NRC did not agree with the use of the LBB methodology as the basis for the 1990 decision to not include the thermal loads following a large-bore pipe break as a design condition for OTSG tubes. This initiated a review to determine the most appropriate way to address the potential consequences of a large-bore pipe break on the OTSG tubes. The review included a determination of the RCS locations where a large-bore pipe break could theoretically produce more limiting tube loads than those previously considered (see Appendix A). This review concluded that the RCS refill phase following a LOCA in the hot leg U-bend could result in increased tube loads because of the large tube-to-shell temperature difference that may be established. This Topical Report provides that technical basis and the corresponding proposed change to the licensing basis. Because the event was determined to have a low risk, AREVA NP and the utilities with B&W-designed plants developed a revised, risk-informed technical basis to address the potential tube loads from a range of postulated breaks in the upper RCS hot leg. The hot leg break sizes and locations that are no longer included are any that produce tube-to-shell temperature differences larger than that predicted by the limiting attached pipe break. Figures A-21 and A-22 show the estimated break size and general locations that exceed the limiting pressurizer surge line break for the lowered-loop and raised-loop plants, respectively. They are described in this Topical Report as "upper" hot leg breaks because they are located in the vertical-riser or hot leg U-bend piping.

While the discussion in this Topical Report is focused primarily on currently operating steam generators, the conclusions are applicable to replacement Once-Through Steam Generators (ROTSGs) and Enhanced Once-Through Steam Generators (EOTSGs) as well. As shown in Figure 1-2 and Figure 1-3, the replacement and enhanced OTSG designs are very similar to the existing OTSG design. In particular, they are straight-tube, once-through designs with tubes expanded and seal welded at both ends. They are designed to have similar performance characteristics as the original components. Therefore, their response to thermal-hydraulic transient conditions, in particular the induced thermal load on the tubes, will be comparable. There may be some differences in the material of the tubes (Alloy 690 vs. Alloy 600) and the shell, as well as the tubesheet thickness, that may result in slightly different tube loads. However, these differences are not significant enough to change any of the discussion or conclusions made in this Topical Report. Accordingly, the technical basis developed in this Topical Report for the requested OTSG licensing basis change is applicable to the ROTSG and EOTSG.

This Topical Report was prepared following the guidance for the elements and principles of risk-informed submittals provided by Regulatory Guide (RG) 1.174. The four elements consist of defining the proposed change, performing engineering analysis, defining implementation strategy and monitoring programs, and submitting the proposed change. The proposed change (Element 1) is defined in Section 2. Section 3 describes the engineering analysis (Element 2), and the implementation and monitoring programs (Element 3) are discussed in Section 4.

RG 1.174 also states that when using risk-informed decision-making, the proposed changes are expected to meet a set of key principles, which span both traditional deterministic and risk analysis methods. The principles (from RG 1.174) are:

1. Meets current regulations unless exemption is requested
2. Change is consistent with defense-in-depth philosophy
3. Change maintains sufficient safety margins
4. Increase in core damage frequency (CDF) or risk is small
5. Impact will be monitored using performance measurement strategies

These principles are discussed in Sections 3 and 4.

Figure 1-1 OTSG Longitudinal Section

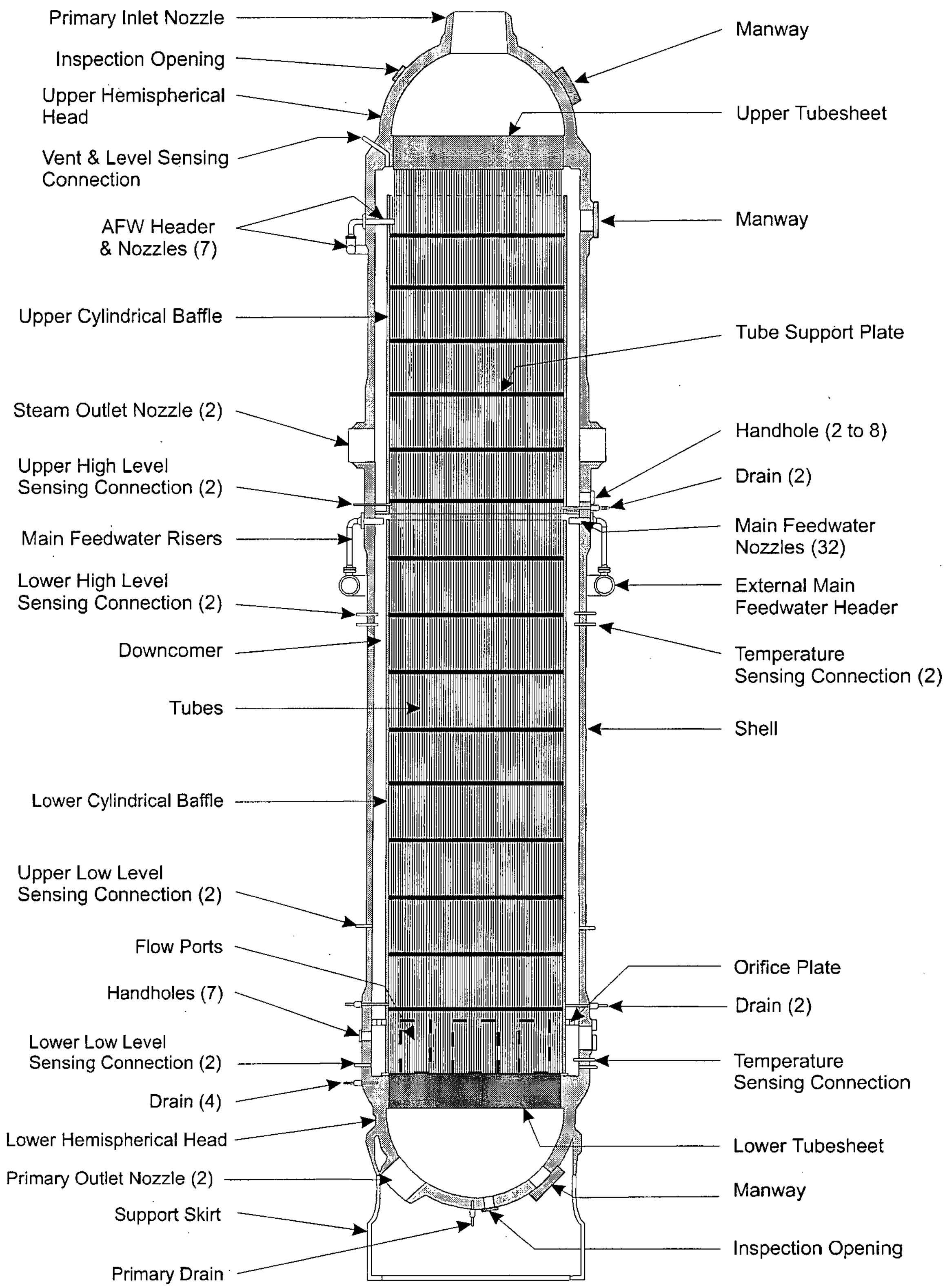
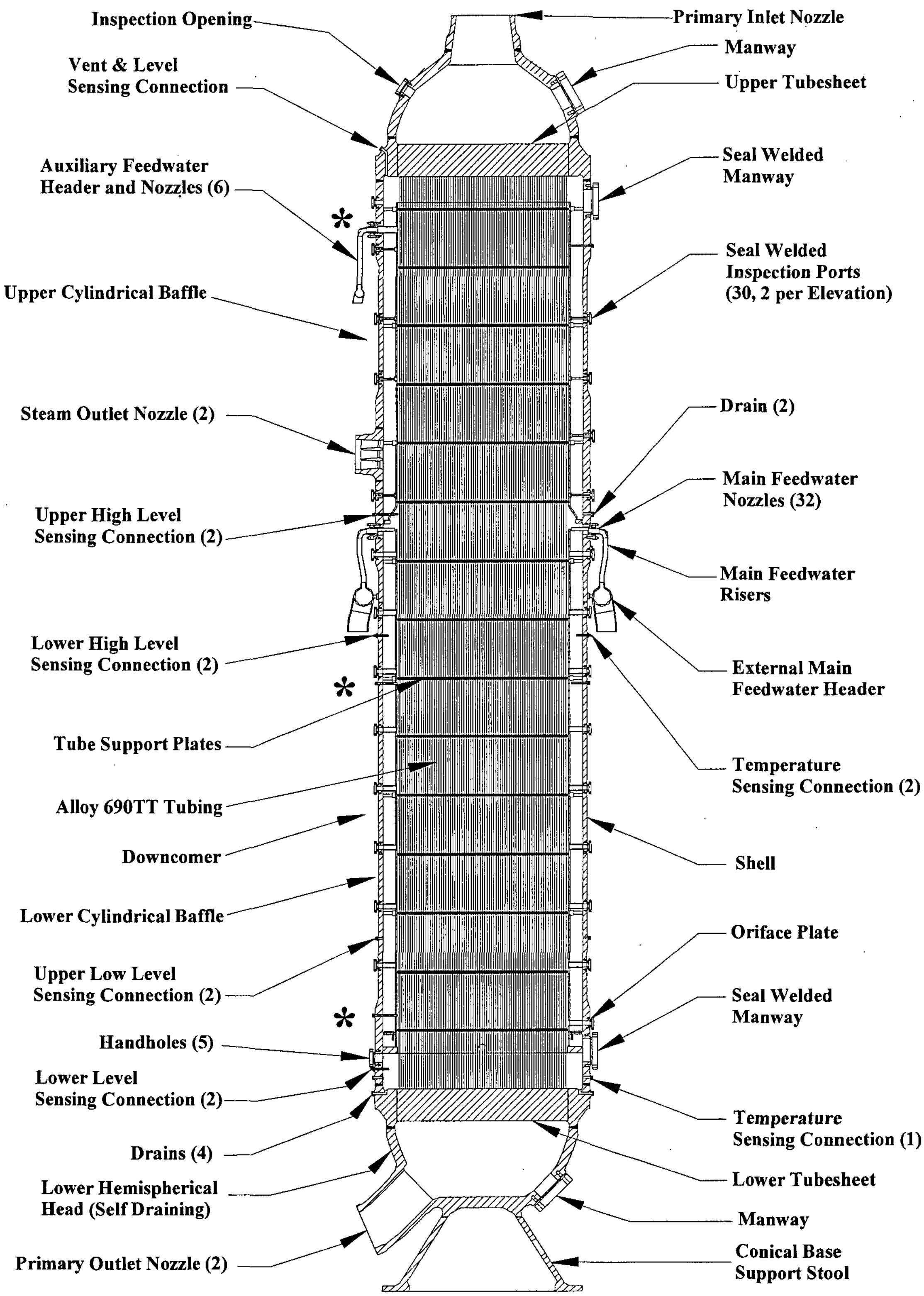
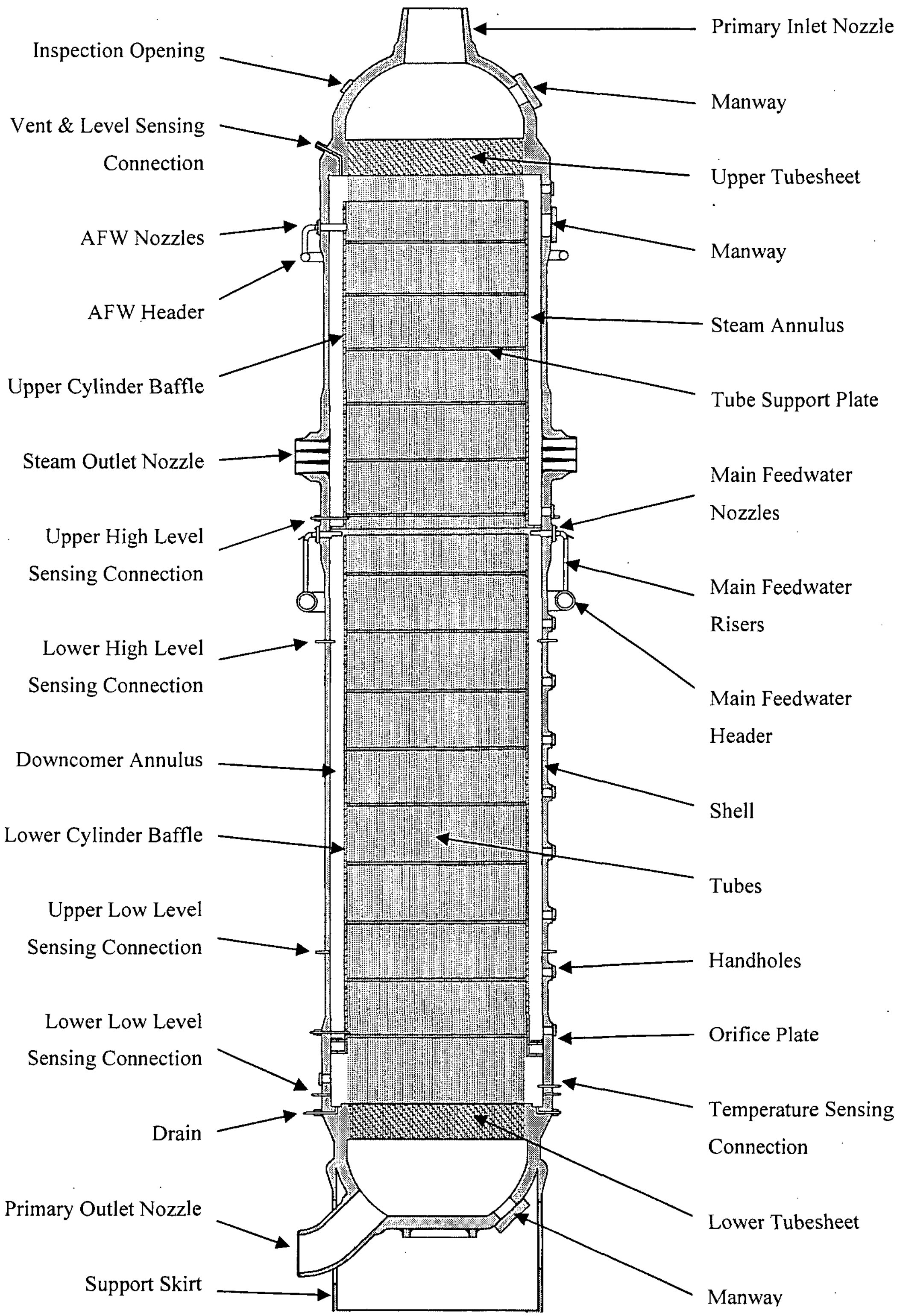


Figure 1-2 Replacement OTSG (ROTSG) Longitudinal Section



* Sample Tap Connections

Figure 1-3 Enhanced OTSG (EOTSG) Longitudinal Section



2.0 Definition of Proposed Change (Element 1)

This Topical Report was prepared following the guidance of Regulatory Guide (RG) 1.174. This section of the Topical Report describes Element 1 of RG 1.174, which is a description of the proposed change. It includes identification of systems, structures and components (SSCs) and activities covered by the change, aspects of the licensing basis that may be affected by the proposed change, and other engineering information relevant to the change. RG 1.174 defines a licensing basis change as "modifications to a plant's design, operation, or other activities that require NRC approval." The "licensing basis change" used throughout this Topical Report refers to the B&WOG approach described below.

2.1 Proposed Change to the Licensing Basis

An alternate approach is proposed to demonstrate compliance with the licensing basis for steam generator tube integrity and tube-to-tubesheet joint performance for the specific faulted condition of a large-bore pipe break in the upper RCS hot leg. Steam generator tube integrity during design basis accidents is required or is implied by 10 CFR 50.46, 10 CFR 100 or 50.67, Draft RG 1.121 (incorporated into NEI 97-06), ASME code, and the GDC as discussed below in Section 2.2. For large RCS hot leg breaks, there is a potential compromise of steam generator tube safety margin because, for this specific location, the OTSG thermal loads may be greater than for the previously analyzed limiting LOCA, which is the RCS attached pipe break. The proposed change to the licensing basis is to accept that the allowed primary-to-secondary leakage is greater than 1 gpm and the deterministic safety margin required by Draft RG 1.121 and the ASME code may not be preserved for OTSG tubes, tube-to-tubesheet joints, and repair products for the specific faulted condition of a large-bore pipe break in the RCS hot leg. For all other design basis accidents, the OTSG safety margins are unaffected by the proposed change. The consequence of this change is the possibility that some OTSG tubes or tube-to-tubesheet joints may fail during the specific condition of a large-bore pipe break in the RCS hot leg.

As discussed in Section 3.0 and Appendices E and F, these consequences have been considered and found to be acceptable with respect to the guidance of RG 1.174. The low risk of this scenario, as determined by the inconsequential change in core damage frequency and large early release frequency, and preservation of the principle of defense-in-depth, allows this very limited concession of safety margin. The 10 CFR 50.46 long-term core cooling criteria and 10 CFR 100 or 50.67 criteria are met for all RCS hot leg LOCA break sizes using a primary-to-secondary leakage rate greater than 1 gpm. Therefore, it is proposed that the deterministic licensing basis for the LOCA-induced OTSG thermal load be defined by the previously analyzed limiting LOCA, which is the RCS attached pipe break. The limiting attached pipe break is the pressurizer surge line for the 177-fuel assembly (FA) Lower Loop plants. The Davis-Besse 177-FA Raised Loop plant uses the limiting thermal loads from the pressurizer surge line break or the continuous upper head vent line break.

For the purposes of this Topical Report, "upper RCS hot leg large-bore piping" refers to the RCS piping in both hot legs at elevations above the elevation of the reactor vessel exit nozzle. In addition, the OTSG upper manways and inspection openings are also included in the scope of this request and references in this report to the upper RCS hot leg are intended to include those as well.

This Topical Report is applicable to both existing and replacement steam generators like the ROTSG and EOTSG.

2.2 Aspects of the Licensing Basis Affected by the Proposed Change

The deterministic approach of 10 CFR 50.46 uses conservative assumptions and boundary conditions, which for the postulated upper hot leg break could create high thermal loads that may result in predictions of tube failure when the upper bound tube load is assessed with conservative deterministic safety margins prescribed in Draft RG 1.121 (incorporated into NEI 97-06). The scope of the proposed change to the licensing basis includes providing an alternate, risk-informed basis for acceptability of the thermal loads on OTSG tubes, tube repair products, and tube-to-tubesheet joints from large-bore upper hot leg pipe breaks. Therefore, compliance with Draft RG 1.121, with respect to thermal loads on OTSG tubes, tube repair products, and tube-to-tubesheet joints, will be demonstrated using the limiting accident conditions from LOCA of RCS attached pipes and MSLB, as applicable.

The ASME Boiler & Pressure Vessel (B&PV) Code currently allows exclusion of secondary stresses (i.e., thermal stresses) from the OTSG for faulted conditions. Per the ASME Code criteria, the pressure load from a large-bore RCS pipe break is a primary load for the steam generators. However, this pressure load is small relative to other design basis events, such as MSLB. Therefore, the discussion in this Topical Report will focus on the OTSG thermal loads. As indicated in Appendix A, the potential OTSG temperature differences (tube-to-shell ΔT) from large-bore RCS pipe breaks in the upper hot leg are in excess of the current analysis for MSLB and LOCA of attached RCS pipes. For most of the OTSG parts (e.g., shell, heads, tubesheets), the thermal loads are classified as secondary stress per the ASME Code criteria and hence do not require evaluation. However, for steam generator tubes, tube repair hardware, and tube-to-tubesheet joints, the axial thermal load associated with the postulated large-bore RCS pipe break event may not satisfy the ASME secondary stress classification. Therefore, the scope of the proposed change includes providing an alternate, risk-informed basis for acceptability of the thermal loads on OTSG tubes, tube repair products, and tube-to-tubesheet joints from large-bore upper hot leg pipe break. The limiting accident conditions from existing analyses of pipes attached to large-bore pipes (such as the pressurizer surge line) and MSLB will be used for the thermal and pressure loads associated with ASME Code evaluation of OTSG tubes, tube repair products, and tube-to-tubesheet joints.

Approval of this report will provide regulatory acceptance that the thermal loads from RCS upper hot leg breaks have been adequately addressed, on a risk-informed basis. This will support the licensing basis for existing OTSG tube repair hardware and maintenance practices. In addition, regulatory approval of the B&WOG approach can be referenced in the licensing basis of future repair products, maintenance practices, and replacement steam generators. The design, testing, inspection, plugging/repair criteria, physical and material properties, and integrity program of the OTSGs will not change as a result of approval of the requested licensing basis change. It is not the intent of this request to alter the ASME B&PV Code Section III or Construction Code requirements to which the original OTSGs were designed and fabricated, nor to which the replacement OTSGs are to be designed and fabricated. The intent is to not explicitly include thermal loads from an upper hot leg large-bore RCS pipe break in the design specifications for all OTSG Section XI and safety-related repairs, replacements, modifications, and inspections of tubes, tube-to-tubesheet joints, and tube repair products. Although some licensing documents (such as Final Safety Analysis Report text and Technical Specifications references) may require revision, the design criteria currently practiced for the OTSG will not change. In addition, there will be no changes to other SSCs, procedures or activities as a result of the NRC's approval of the B&WOG approach. Necessary document revisions will be made by the individual licensees in accordance with applicable NRC regulations.

The B&WOG reviewed 10 CFR 50 to determine if an exemption, pursuant to 10 CFR 50.12, is needed in order for the NRC to approve the requested change to the OTSG licensing basis. (A B&WOG evaluation of the General Design Criteria is included in Appendix D.) The review concluded that no exemption is required; however as discussed in Appendix D, some of the GDC allow the use of probability to demonstrate compliance. As a risk-informed submittal, this Topical Report supports the demonstration of compliance with GDC 14 and the other GDC with respect to demonstrating low probability of certain accident scenarios. This Topical Report provides an alternate, risk-informed basis for acceptability of the thermal loads on OTSG tubes, tube repair products, and tube-to-tubesheet joints induced by an upper hot leg large-bore pipe break. Therefore, for the purpose of meeting the intent of the GDC with respect to the thermal loads on OTSG tubes, tube repair products, and tube-to-tubesheet joints, the limiting postulated accident is a LOCA in RCS attached pipe or MSLB.

Other than demonstration of no cladding rupture for this hot leg LOCA scenario and the Licensing Commitments or Technical Specification additions (see Appendix G), there are no other aspects of the plants' licensing basis, including regulations (10 CFR 50), final safety analysis report (FSAR) analysis, licensing conditions, or licensing commitments that are affected by the proposed change.

2.3 Why the Proposed Change is Needed

Framatome ANP and the B&WOG have previously not included upper hot leg large-bore pipe breaks in determining the bounding tube-to-shell temperature differences from which thermal loads on the steam generator tubes were calculated. The analyzed loss of primary system coolant events have been limited to lower hot leg pipe breaks or breaks in smaller RCS attached pipes. These break sizes and locations (below the top of the steam generator tubes) passively limit the magnitude of the shell-to-tube thermal difference. The most recent analyses of the pressurizer surge line break resulted in temperature differences between 225°F to 235°F (see Appendix A, Section A.4.2). Analysis of a postulated guillotine break near the top of the large-bore hot leg predicted a maximum plant-specific shell-to-tube thermal difference of between 350°F to 370°F, because it results in additional tube cooling from the pumped emergency core cooling system (ECCS) flow through the tubes to the break location.

The high thermal tube loads produced during the refill of the RCS during an upper hot leg piping break could cause a larger as-found circumferential or volumetric tube flaws to progress to a through-wall crack or possibly sever, which would create a leak rate that will exceed the one gallon per minute limit. If there are multiple tubes with flaws that could produce through-wall cracks, then compliance to the long-term core cooling or dose regulations must be demonstrated. Postulating a large number of failed tubes allows flexibility for future tube inspections, but it can force changes to the time-critical EOP action sequences to preserve liquid inventory necessary for long-term core cooling. It is not desirable to reorder or displace higher priority EOP actions to address this low probability hot leg break scenario unless absolutely necessary. Therefore, the historical tube inspection data for all OTSGs is used to define how many tubes could realistically be expected to fail. The historical data suggests that there are few significant as-found free span tube flaws during any outage and only one or possibly two of them could realistically progress to a through-wall crack or sever from the upper hot leg LOCA induced thermal loads. Demonstrating acceptable long-term core cooling with four free span tube severs strikes a balance between not perturbing the EOP action sequences and maintaining some margin to address as-found future tube flaws. Limiting the leakage area to four tubes manages the total leakage rate and provides sufficient time for secondary side isolation, via both automatic actions and operator actions, to limit the RCS inventory loss such that long-term core cooling is preserved as shown in Appendix E. In addition, when long-term core cooling is preserved, it maintains acceptable dose consequences as described in Appendix F.

Approval of the B&WOG request will reduce the potential for premature plugging of steam generator tubes that have insignificant flaws. If the acceptability of OTSG thermal loads were to be based entirely upon the upper hot leg large-bore pipe break, the limiting loads would result in additional restrictions for tube repair products and lower the threshold for detecting flaws below what the current technology provides. This would result in additional inspection requirements and plugging of tubes with adequate pressure boundary integrity. These consequences would be excessively burdensome and unnecessary, considering that the likelihood of the postulated large-bore pipe break is very small (see Appendix C), and the consequences of the resulting thermal loads on the steam generator (possible LOCA-induced steam generator tube rupture) are not risk-significant (see Section 3.4).

3.0 Engineering Analysis (Element 2): Development of RG 1.174 Principles

This Topical Report was prepared following the guidance provided by Regulatory Guide (RG) 1.174. This Section describes the engineering analysis. RG 1.174 states that when using risk-informed decision-making, the proposed changes are expected to meet a set of key principles, which span both traditional deterministic and risk analysis methods. These principles (from RG 1.174) are:

1. Meets current regulations unless exemption is requested
2. Change is consistent with defense-in-depth philosophy
3. Change maintains sufficient safety margins
4. Increase in CDF or risk is small
5. Impact will be monitored using performance measurement strategies

These are described in the subsections below. Principle 5 is discussed in Section 4.

3.1 Meets Current Regulations

The proposed licensing basis change will not affect compliance with the current regulations as specified in 10 CFR 50, 50.67 or 100 because all hot leg LOCAs are considered and the dose is bounded by other accidents. Appendix E describes the LOCA, containment pressure, steam generator leakage rates, and plant net positive suction head (NPSH) analyses, which rely on operator actions to isolate all secondary side leak paths not automatically closed, to demonstrate compliance to the long-term core cooling criteria of 10 CFR 50.46. Appendix F describes the limiting hot-leg U-bend LOCA fuel pin cladding rupture analyses performed with an approved LOCA evaluation model to demonstrate that the cladding does not rupture. The results of the cladding rupture study are used to develop the appropriate source terms for the Part 100 or 50.67 evaluations that concluded the hot leg U-bend LOCA scenario is bounded by other accidents.

Therefore, based on the work described in this Topical Report, the proposed change requires no specific exemption (pursuant to 10 CFR 50.12) or petition for rulemaking (pursuant to 10 CFR 2.802). As discussed in Section 2.1, Section 2.2 and Appendix D, the B&WOG has reviewed the regulations and has determined that an exemption is not required for the NRC to approve the request.

3.2 Change is Consistent with Defense-in-Depth

The proposed licensing basis change is consistent with the defense-in-depth philosophy as discussed in RG 1.174.

The balance between prevention of core damage and prevention of containment failure/consequence mitigation is not affected by consideration of OTSG tube loads induced by large-bore RCS pipe break. The calculations presented in Section 3.4 show that the relative proportion of CDF to large early release frequency (LERF) is maintained when the LOCA-induced steam generator tube rupture (SGTR) scenarios are considered. For these scenarios, the ΔLERF is about a factor of 20 less than the ΔCDF, which is in the same approximate proportion as is typical for overall plant CDF and LERF. In addition, neither the incremental CDF nor the incremental LERF from the LOCA-induced SGTR is significant enough to affect the overall plant CDF or LERF.

Traditional defense-in-depth considerations are also maintained. The concepts of system redundancy, independence, and diversity are not compromised by the proposed change. As shown in Section 3.4, many failures must occur in order for core damage or large radiological release to occur due to the LOCA-induced tube loads:

- a large-bore pipe break in a specific location (the upper hot leg),
- steam generator (SG) tube pressure boundary damage,
- a secondary side isolation failure,
- a failure of ECCS Low Pressure Recirculation, and

- for a large release, an unscrubbed release pathway via the secondary side/balance of plant (BOP).

The independence of barriers is not degraded by the proposed licensing basis change. Calculations described in Appendix F demonstrate that the fuel pin clad remains intact during the blowdown and reflood phases of the event for the hot leg U-bend LOCA. In the unlikely event of significant tube leakage, the containment barrier is not lost unless there are additional independent failures of secondary side isolation, and failure of operator accident management response.

Plant and operator response varies depending upon the size of the break. The large-bore pipe breaks that may lead to thermal loads in excess of the attached pipe break thermal load are discussed in Appendix A. These breaks must occur in the upper hot leg large-bore piping above the horizontal pipe run. The most limiting break locations are in the U-bend of the upper hot leg. For these breaks, the ECCS refills the RCS including the hot leg and OTSG tube regions of the broken loop, and a continuous liquid flow through the OTSG tubes and out the break is established. This liquid throughput cools the OTSG tubes and can eventually result in a large tube-to-shell temperature difference, which results in the higher tube loads. The larger size breaks, up to a double-ended guillotine hot leg break, produce the highest OTSG tube thermal loads.

For the postulated upper hot leg large-bore pipe break scenarios, ECCS flow refills the RCS and OTSG tubes causing the secondary side pressure to drop to a pressure corresponding to the fluid temperature in the tubes. This pressure will tend to be less than RCS pressure. For all the postulated break sizes, OTSG pressure decreases and remains low (see Appendix A), leading to secondary side isolation. For those plants having secondary plant protection systems (e.g., EFIC), secondary side isolation will be achieved when OTSG pressure drops below predetermined values. For all plants, cognitive skills provided by recurrent operations staff training reinforce the need to address and mitigate upsets in plant processes. This provides reasonable assurance that operations personnel, including control room and technical support center staff, will address these plant conditions and isolate OTSGs, even in the absence of installed secondary plant protection systems. This is reinforced by plant operations guidance that isolates OTSGs following recovery from a LBLOCA.

For the upper hot leg large-bore pipe breaks, consequential failure of OTSG tubes is postulated to occur along with an independent failure of secondary side isolation. If there is significant primary-to-secondary leakage due to such an occurrence, plant operations personnel will be alerted to the situation by an uncontrolled increase in OTSG level or possibly by radiation monitors that may detect radioisotopes in the reactor coolant passing through the secondary side. Thus, isolation of the OTSGs, i.e., the secondary side, will occur and the flow of reactor coolant through these lines will be terminated. Main steam safety valve (MSSV) failure is unlikely because for the postulated event scenario SG pressure decreases and remains low. For a double-ended guillotine break, the MSSVs will not be challenged at all. For break sizes less than that, some safety valves may initially open in response to reactor trip, but the secondary side pressure will drop so low (approaching an equilibrium pressure near atmospheric) that it is unlikely that the safety valves will remain open. All secondary flow paths other than the MSSVs have additional valves for isolation and plant operations guidance provides valve lists for isolating the OTSGs.

Significant core (fuel pin clad barrier) damage will not occur (see Appendix F) unless there is a failure of ECCS. However, substantial ECCS flow is required to produce the OTSG tube thermal loads that are at issue. Therefore, a severe accident will not occur unless there is an independent failure of ECCS later in the event (i.e., in the recirculation phase), or unless the containment bypass through the postulated tube breaks and secondary side isolation failure is allowed to continue until all of the ECCS and RCS inventory is lost out the secondary side. In this case, there would be a period of time before the core uncovers while operations staff will be making every effort to preserve and replenish ECCS inventory (see Section 3.4.6).

The EOPs are separate and distinct from the 10 CFR 50 Appendix K analyses. While Appendix K applications use only safety-related equipment to demonstrate compliance, the EOPs instruct the operators to use safety as well as non-safety grade equipment that may be available to maintain the ECCS function following a LOCA. Additional actions will likely be directed by the shift technical advisor and technical support center, including refilling the BWST from an alternate source of borated water.

The plant's defenses against common cause failure and human errors are preserved. Relative to human errors, plant procedures provide guidance on mitigation of transients where OTSG tubes fail. No new accident initiators, common cause failures, or human errors are introduced as a result of the proposed change. No changes to the operating procedures, maintenance procedures, or SSC design are required to implement the proposed change.

Table 3-1 provides a summary of the defense-in-depth considerations from RG 1.174.

3.3 Change Preserves Sufficient Safety Margins

The design of the OTSG is governed by the requirements of Section III of the ASME B&PV Code. Various editions were used to design the operating plants, but the fundamental acceptance criteria are the same. Essentially, the ASME Code requires that the components be designed so that the specified criteria are met for all design conditions.

Once the plant is operating, the maintenance and repair of the plant is governed by Section XI of the ASME Code, as well as applicable Regulatory Guides. For OTSGs, the tubes are of particular interest. The NRC has issued guidance for licensees to ensure that the tubes are inspected with sufficient frequency and with acceptable techniques, and that criteria are developed that force the repair of tubes that have unacceptable levels of degradation. Draft Regulatory Guide 1.121 (incorporated into NEI 97-06) contains the current requirements for determining how degraded tubes are evaluated, including required safety margins. In general, Draft RG 1.121 enforces the design requirements of the ASME Code, and in addition specifies that tubes shall have a margin to burst of 3.0 for normal operating conditions, and 1.4 for faulted conditions.

B&WOG plant programs provide assurance that the safety margins for OTSG tube integrity and tube-to-tubesheet joint performance are maintained under analyzed limiting conditions (i.e., RCS attached pipe break and MSLB). As discussed in Section 4, operational assessments are performed to provide assurance that the OTSGs will maintain their structural integrity and accident leakage integrity through each forthcoming cycle. In addition, plugging and repair methods are qualified and implemented in accordance with the applicable codes and regulations. These qualification reports include tests and evaluations to demonstrate OTSG structural integrity and safety margin for the analyzed limiting conditions (i.e., RCS attached pipe break and MSLB).

For the specific case of the thermal loads caused by a large-bore pipe break in the upper RCS hot leg, the safety margin in OTSG tube integrity and tube-to-tubesheet joint performance may not be preserved. This may result in the possibility that some OTSG tubes will fail during the unlikely event of a large-bore pipe break in the upper RCS hot leg. However, the potential safety margin concession for this specific condition is acceptable because the risk to public health and safety is "very small" according to the acceptance guidelines of RG 1.174 (see Section 3.4). This is as demonstrated by minimal changes in core damage frequency and large early release frequency, and maintenance of defense-in-depth principles.

For all other design basis accidents, the OTSG safety margins are unaffected by the requested change and the tubes, tube repair products, and tube-to-tubesheet joints will continue to meet all existing regulations and requirements.

In the current OTSG licensing basis, the limiting accident conditions are RCS attached pipe breaks and MSLB. With approval of the B&WOG request, the limiting accident conditions will remain RCS attached pipe breaks and MSLB. Therefore, the existing safety analysis ensures that the limiting events, considering risk significance, have been evaluated, and that current safety margins are maintained. These limiting events have been analyzed for OTSGs, and the resulting loads on the steam generator components have been determined. The affected tube repair processes and products have been confirmed by analysis or testing to meet the safety margins required by the ASME Code and Draft RG 1.121 (incorporated into NEI 97-06), as applicable. Therefore, the design of the OTSG will continue to meet the safety margins required by the applicable codes and standards after the requested change is approved.

Table 3-1 Disposition of Reg. Guide 1.174

Defense-in-Depth Considerations

CONSIDERATION	DISPOSITION
A reasonable balance is preserved among prevention of core damage, prevention of containment failure, and consequence mitigation.	This balance is unaffected by this request. The relative proportion of large early releases to core damage is roughly the same as a typical pressurized water reactor (PWR) probabilistic risk assessment (PRA). In addition, the scenarios of concern are very low frequency, even when bounding assumptions are used.
Over-reliance on programmatic activities to compensate for weaknesses in plant design is avoided.	No new programmatic activities are involved.
System redundancy, independence, and diversity are preserved commensurate with the expected frequency, consequences of challenges to the system, and uncertainties (e.g., no risk outliers).	System redundancy, independence, and diversity are unaffected by the requested change to the licensing basis.
Defenses against potential common cause failures are preserved, and the potential for the introduction of new common cause failure mechanisms is assessed.	No new common cause failures are introduced by the requested change. Existing common cause failures are not impacted.
Independence of barriers is not degraded.	Multiple failures must occur before core damage or large release. Containment bypass requires independent failure of secondary isolation and failure of backup operator actions. High tube load scenario requires full ECCS flow, which precludes fuel barrier degradation. Low RCS pressure limits the driving force for leakage. Core damage requires independent ECCS failure or operator failure later in event.
Defenses against human errors are preserved.	No new human errors are introduced by the requested change. Existing operator guidance is not affected by the change.
The intent of the General Design Criteria in Appendix A to 10 CFR 50 is maintained.	The B&WOG performed an evaluation, which demonstrates that the GDC are maintained (see Appendix D).

3.4 Change in CDF and LERF is Small

A bounding risk analysis has been performed to estimate the potential risk contribution (i.e., ΔCDF and ΔLERF) from possible loss of OTSG tube integrity due to tube loads induced by large-bore RCS pipe break. This represents the estimated risk impact of the proposed licensing basis change, for comparison to RG 1.174 criteria. However, the actual plant risk will not change as a result of NRC approval of the requested licensing basis change. The risk will not change because there will be no change to any SSC, inspection criteria, or test and maintenance program. The thermal loads from failure of the large-bore piping have not been used to develop any OTSG design or operational parameters. Accordingly, there is no incremental change in risk relative to the current design. Nonetheless, the potential risk "increase" (i.e., ΔCDF and ΔLERF) from the postulated LOCA-induced SGTR scenarios is estimated to show that the tube loads are not risk significant (compared to RG 1.174 criteria).

3.4.1 Definition of LERF

For the purposes of determining the increase in risk, this analysis uses CDF and LERF as the metrics for comparison to the acceptance guidelines of Regulatory Guide 1.174. The definition of LERF from RG 1.174 has been adopted for this analysis. The following is an excerpt from the RG 1.174:

> The use of core damage frequency (CDF) and large early release frequency (LERF) as bases for probabilistic risk assessment (PRA) acceptance guidelines is an acceptable approach to addressing Principle 4. ... In this context, LERF ... is defined as the frequency of those accidents leading to significant, unmitigated releases from containment in a time frame prior to effective evacuation of the close-in population such that there is a potential for early health effects. Such accidents generally include unscrubbed releases associated with early isolation.

The PRA scenarios developed below use this definition of LERF. For the B&WOG plants, the estimated time frame prior to the effective evacuation of the close-in population is typically 3 to 5 hours. EOPs provide guidance for appropriate personnel to assess emergency action levels (EALs), based on LOCA symptoms. This will initiate nearly immediate notification of personnel/authorities responsible for site and general emergency planning, including any necessary evacuation of local populations ensuring that public health effects are minimized.

3.4.2 Development of LOCA-Induced SGTR Scenarios

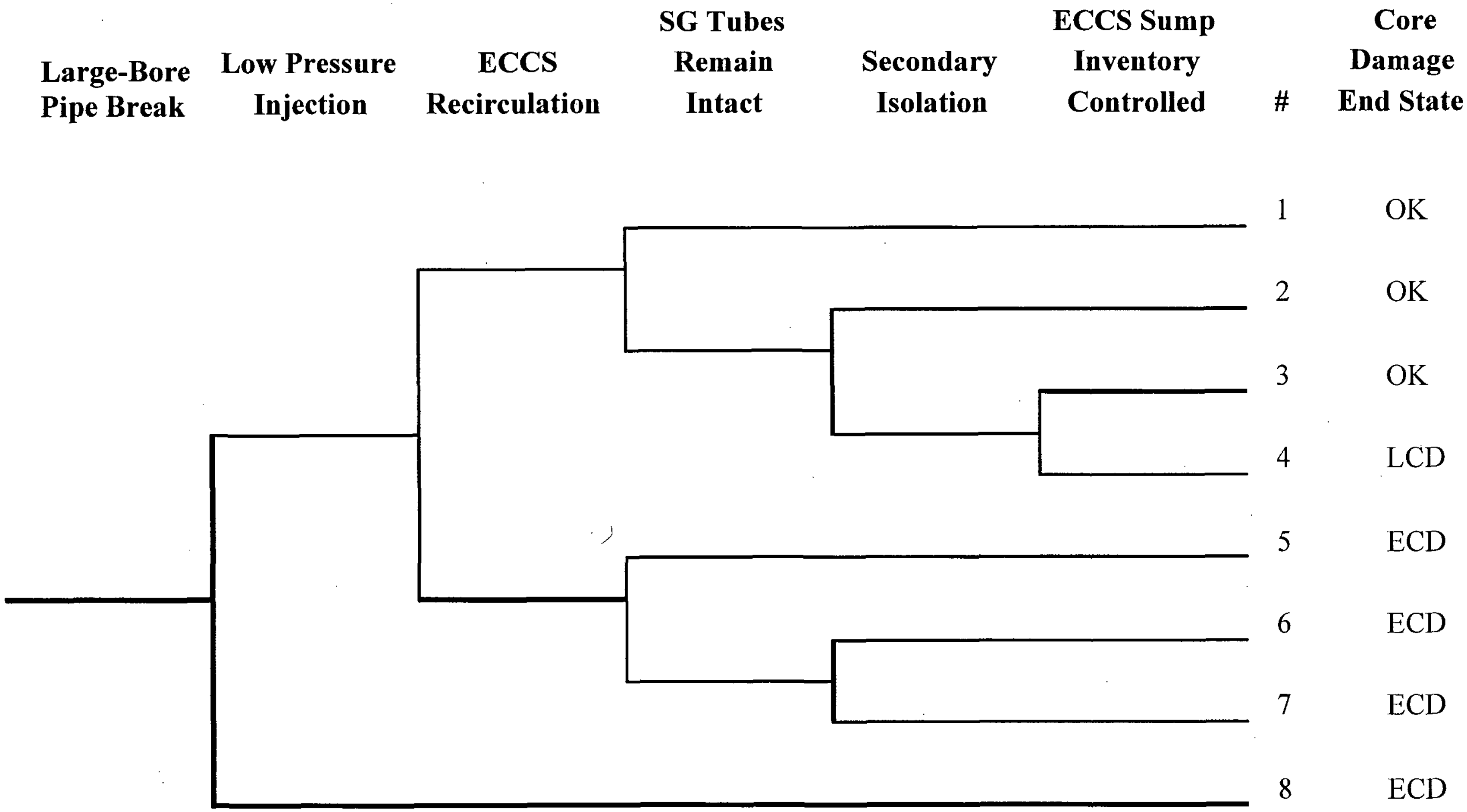
The change in CDF and LERF is estimated for the postulated LOCA-induced SGTR scenario. This change in risk is that "new" risk from those LOCA-induced tube loads that are not currently considered in the OTSG licensing basis, and which therefore may produce event sequences/risk contributions that are not included in the current B&WOG plant-specific PRAs. As indicated in Appendix A, only the OTSG temperature differences (tube-to-shell ΔT) from large-bore RCS pipe breaks in the upper hot leg are in excess of current safety analysis for MSLB and LOCAs in RCS attached pipes. Hence, PRA scenarios are developed that involve LOCA-induced steam generator tube rupture due to breaks in the upper RCS hot leg.

Figure 3-1 is an event tree illustrating the LOCA-induced SGTR scenarios. The scenarios of interest begin with a LOCA in the large-bore piping in the upper (i.e., U-bend or "candy cane") region of the RCS hot leg. ECCS refills the RCS including the hot leg and SG tube regions of the broken loop, and a continuous liquid flow through the SG tubes and out the break is established. This liquid throughput can eventually result in a large tube-to-shell temperature difference, which is assumed to induce a SGTR. In Figure 3-1, only sequences 2 through 4, and sequences 6 and 7 involve the LOCA-induced SGTR of interest. In order for the induced SGTR to be of consequence, with respect to CDF or LERF, there must also be a failure of secondary side isolation. Thus, sequences 2 and 6 are of no further interest because of successful secondary side isolation. Sequence 3 is also of no interest because ECCS recirculation is successful, and there is no core damage. This leaves two LOCA-induced SGTR scenarios (sequences 4 and 7 from Figure 3-1) that warrant further consideration.

As discussed, sequences 4 and 7 both start with a LOCA in the upper RCS hot leg. The RCS is refilled by ECCS, which induces a SGTR in the broken RCS loop. Both postulated scenarios involve secondary side isolation failure, but with different results. In the first scenario (sequence 4), the isolation failure leads to eventual depletion of reactor building (RB) sump inventory through the secondary side, which causes late core damage. There is no large early release in this scenario. In the second scenario (sequence 7), a large early release occurs because an independent failure of ECCS recirculation results in early core damage at about 35 minutes after event initiation (the success of ECCS is requisite for the induced SGTR). The release occurs via the secondary side isolation failure. These sequences are treated in detail in the subsections below.

It is noted that the thermally-induced tube loads from these events are not expected to result in significant OTSG tube leakage (see Appendix E). However, significant OTSG tube leakage is conservatively assumed in the PRA sequences, so that the risk estimate will bound any uncertainty associated with SG tube integrity. In addition, operator actions that are credited for recovery from these events are treated with conservative values for human error probability.

Figure 3-1 Large-Bore Pipe Break Event Tree Considering Steam Generator Tube Failure



LCD = Late Core Damage
ECD = Early Core Damage

Figure 3-1 (Continued)

Evaluation of Large-Bore Pipe Break Event Sequences

SEQ	DESCRIPTION	NEW SCENARIO?	DISCUSSION
1	This sequence does not involve core damage. All necessary systems and structures function successfully.	No	Non-Core Damage Event
2	This sequence does not involve core damage. All necessary systems function successfully and although the steam generator tube integrity is challenged, secondary isolation ensures no significant release.	No	Non-Core Damage Event
3	This sequence does not involve core damage. All necessary systems function successfully and although the steam generator tube integrity is challenged, and secondary isolation does not occur, makeup of primary inventory ensures no core damage.	No	Non-Core Damage Event
4	This sequence involves successful ECCS injection and recirculation. However, failure to isolate the secondary side and failure to makeup for ECCS sump inventory released over time to the secondary side leads to core damage.	Yes (CDF)	The traditional PRA would not have dealt with this scenario because with the SGs intact, there would not have been a pathway for primary coolant to be lost.
5	This sequence involves success of low pressure ECCS injection followed by failure of ECCS during recirculation. It is considered in the traditional PRA analysis of large LOCAs. SGs are intact.	No	Considered in traditional PRA of Large LOCA.
6	This sequence involves success of low pressure ECCS injection followed by failure of ECCS during recirculation. Successful isolation of the secondary side leads to a core damage event with containment isolated.	No	LOCA with loss of ECCS recirculation is considered in traditional PRA. There is a slight difference, in that it would typically not consider secondary isolation. However, because the release is prevented, this sequence does not result an increase in CDF or LERF due to loss of SG integrity.
7	This sequence involves success of low pressure ECCS injection followed by failure of ECCS during recirculation. Failure to isolate the secondary side leads to a core damage event with containment bypass.	Yes (LERF)	The core damage contribution from this sequence would be considered in a traditional PRA. However, the failure to isolate the secondary side leads to a new LERF scenario.
8	This sequence involves a failure of low pressure ECCS injection. It is considered in the traditional PRA analysis of large LOCAs and does not challenge SG tube integrity.	No	Considered in traditional PRA of Large LOCA.

3.4.2.1 Description of Sequence 4

Sequence 4 is a LOCA-induced SGTR with secondary side isolation failure, and core damage due to eventual loss of RB sump inventory through the secondary side. The failures required for an increase in CDF include:

- LOCA in large-bore RCS piping (initiating event); break is in specific RCS location (upper hot leg) to induce high tube axial loads as a result of thermal stresses,
- OTSG tube RCS pressure boundary failure,
- Coincident failure of secondary side isolation, that is not mitigated by operator action, leading to loss of primary inventory and eventual ECCS recirculation failure.

There is no increase in LERF for this sequence because there is no early release. An early release is one in which the release is in a time frame prior to the effective evacuation of the close-in population (see Section 3.4.1). In this sequence, core damage does not occur early. A prerequisite of the induced OTSG tube failure is refilling of the RCS and OTSG tubes with low enthalpy ECCS water. For large-bore piping failures that lead to full ECCS flow rates and cause consequential OTSG tube failures, analysis indicates that the maximum tube-to-shell differential temperature will occur between 12 and 15 minutes following event initiation (see Appendix A). Based on nominal ECCS flow rates, about 50% of the available ECCS inventory will still remain in the borated water storage tank (BWST) (for subsequent RCS injection) at the time of tube failure, if it occurs. At this time, the depleted BWST inventory will have been transferred to the RB sump via the postulated hot leg break and RB spray. It is assumed that primary inventory losses through a failed secondary side isolation point commence at the time of OTSG tube failure. The remaining contents of the BWST will then pass to both the RB sump and the failed secondary side isolation point. Since the pressures on both the primary and secondary side of the OTSG will be low, and nearly equal, the driving force (ΔP) for leakage losses will be small. Due to this and the resistance to flow associated with the leak path through the secondary side, the flow rate through this path will be relatively small compared to that flowing to the RB sump via the hot leg break and RB spray. Therefore, the majority of the remaining BWST inventory will be transferred to the RB sump. Following ECCS suction transfer to the RB sump, the time to deplete the RB sump inventory will depend on the leak rate through the failed OTSG tubes and secondary side failed isolation point. Again, due to available primary to secondary ΔP and resistance to flow associated with the leak path through the secondary side, the majority of recirculating ECCS flow will return to the RB sump via the break and RB spray. For this reason, loss of RB sump inventory through the secondary side leak will be relatively slow allowing for an extended period of operation in the RB sump recirculation mode prior to core damage. This sequence is supported by calculations described in Appendix E. Hence, core damage, if it eventually occurs, will occur late.

EOPs provide guidance for appropriate personnel to assess EALs based on LOCA symptoms. These symptoms will occur very early in the transient and will lead to EAL notification of personnel/authorities responsible for site and general emergency planning, including evacuation of local populations. Because of this, evacuation if necessary will be accomplished in a timely fashion, thus minimizing public health effects.

3.4.2.2 Description of Sequence 7

Sequence 7 is a LOCA-induced SGTR, also with secondary side isolation failure. However, core damage occurs early (at about 35 minutes after event initiation), following depletion of the BWST, due to independent failure of ECCS recirculation. This scenario does not represent an increase in CDF because it is already included in the plant PRAs, minus the induced SGTR. However, an increase in LERF is possible due to the assumed SGTR (which occurs between 12 and 15 minutes after event initiation) and secondary isolation failure. The failures required for an increase in LERF include:

- LOCA in large-bore RCS piping (initiating event); break is in specific RCS location (upper hot leg) to induce high tube axial loads as a result of thermal stresses,
- OTSG tube RCS pressure boundary failure,

- Coincident secondary side isolation failure without mitigating operator action,
- ECCS failure upon switchover to recirculation mode,
- Unscrubbed release pathway in secondary side/BOP.

3.4.2.3 Other Scenarios

In another postulated scenario (not shown on Figure 3-1), core damage is caused by boron dilution from the secondary side (see Generic Issue 141 of NUREG-0933 [7]). However, that scenario is not applicable to this issue. When the secondary side pressure is greater than the primary side pressure, the tube-to-shell temperature difference is not sufficient to cause tube failure. Later during the transient, when the thermal load-induced tube failure could occur, secondary side pressure is either less than primary side pressure or equilibrates near primary side pressure, i.e., 0 psi differential pressure.

For those plants having secondary plant protection systems (e.g., EFIC), secondary side isolation will be achieved when OTSG pressure drops below predetermined values. For all plants, cognitive skills provided by recurrent training reinforce the need to address and mitigate upsets in plant processes. This provides reasonable assurance that operations personnel, including control room and technical support center staff, will address these plant conditions, e.g., low OTSG pressure and uncontrolled increase in OTSG level, and isolate OTSGs, even in the absence of installed secondary plant protection systems. During the recovery phase, static heads could lead to some limited RCS in-leakage, especially if the tube failures occur at lower OTSG elevations. However, any minimal RCS in-leakage would flow up the tubes with the ECCS liquid and out of the break. Mixing in the sump could minimally reduce the overall sump concentration, but it would be of no concern, even if the volume of fluid transferred to the RCS included the entire OTSG secondary side inventory. For these reasons, boron dilution caused by flow from the secondary side to the primary side is not a concern for the upper hot leg large-bore pipe break, and will not be considered further in this Topical Report.

3.4.3 Initiating Event Frequency

3.4.3.1 Large-Bore Pipes

The break location of concern for the risk assessment is limited to the 36-inch ID pipe in the "candy cane" portion of the hot leg above the elevation of the horizontal hot leg run (see Appendix A). This is the only location where a break may possibly produce OTSG tube thermal loads significantly in excess of those already analyzed for an attached pipe break or MSLB.

The initiating event frequency for this break is estimated using the method of Idaho National Engineering & Environmental Laboratory (INEEL) from NUREG/CR-5750 [8]. INEEL used the Beliczey and Schulz Correlation to determine the frequency of a LOCA in large pipe. As indicated in the NUREG, the correlation is supported by the work of the Swedish Nuclear Power Inspectorate (SKI), Lawrence Livermore National Laboratory (LLNL), Pacific Northwest National Laboratory (PNNL), and Battelle. The expected frequency of any rupture of large-bore piping is given by:

$$\lambda_R = \lambda_{TW} * (P_{R/TW})$$

where:

λ_R = frequency of rupture

λ_{TW} = frequency of through-wall (TW) crack from historical experience

$P_{R/TW}$ = conditional probability of any rupture given TW crack

The correlation for conditional probability of rupture given TW crack is:

$$P_{R/TW} = 2.5 / DN$$

where:

DN= nominal pipe diameter in mm

Since the 36-inch ID (42-inch OD) hot leg piping is custom made, it does not have a "nominal" size. Therefore, the internal diameter (in millimeters) is used, which is conservative:

DN = 914 mm

Thus:

$P_{R/TW} = 2.5 / 914 = 0.0027$

The frequency of a TW crack is determined from historical experience. As indicated in the NUREG, a few TW cracks have occurred in small piping. Most of these have occurred in pipe sizes of 2 inches to 6 inches in diameter. The largest pipe experiencing a TW crack identified in the INEEL data was in an 8-inch diameter pipe in a foreign reactor. In the 3362 calendar years of world-wide pressurized water reactor (PWR) experience that was surveyed by INEEL, no TW cracks occurred in large-diameter pipes. Subsequent to the INEEL evaluation, there has been one TW crack, which was identified at the V. C. Summer nuclear power plant. This was a small axially oriented crack in the lower part of the hot leg near the reactor vessel connection. Appendix C contains an evaluation of the RCS hot leg piping in the B&WOG plants, which supports the conclusion that a TW crack in the large-bore RCS piping is extremely unlikely.

Therefore, if one TW crack is assumed to have occurred in a 36-inch diameter pipe during 3362 years of operation, then the frequency of through-wall cracking in a 36-inch pipe is:

$\lambda_{TW} = 1/3362 \text{ yr} = 3 \times 10^{-4}/\text{yr}$

And the estimated frequency of the 36-inch pipe break is:

$\lambda_R = 8 \times 10^{-7}$/calendar year

This initiating event frequency applies to all of the 36-inch RCS piping. Only the pipe in the upper "candy cane" portion of the hot leg is of interest with respect to large-bore pipe break-induced SGTR. In addition, the Beliczey and Schulz Correlation computes the total frequency of all ruptures of the pipe, including not only the bounding double-ended break, but also smaller ruptures that may challenge OTSG tube integrity to a lesser extent. Therefore, use of this initiating event frequency in the risk calculations is conservative.

This initiating event frequency reconciles favorably with the LBLOCA initiating event frequencies used in the B&WOG PRAs. Most of the B&WOG members are already using NUREG/CR-5750 for their LOCA initiating event frequencies, are transitioning to its use, or are using comparable values. However, the LBLOCA frequency reported in NUREG/CR-5750 is for pipe sizes of 8 inches and up. The large-bore 36-inch RCS piping is a subset of the pipe sizes that are considered in the LBLOCA category. Therefore as expected, the frequency of the 36-inch pipe break is less than for all LBLOCAs.

3.4.3.2 Manways

A LOCA initiating event via failure of the OTSG upper manway or inspection opening is unlikely. Appendix B discusses the B&WOG review of potential manway and inspection opening degradation mechanisms. The review concluded that there is no credible failure mode of any manway or inspection opening component that could result in catastrophic failure of the RCS pressure boundary resulting in a LOCA. Appendix B also discusses the design, inspection, and procedural precautions that are employed to ensure proper installation of manways and inspection openings.

There has been no history of LOCA initiators or precursors caused by manway or inspection opening failures. The research performed by INEEL in the development of NUREG/CR-5750 included an exhaustive search of worldwide operating history for RCS pressure boundary failures. There is no indication from the INEEL work that manways or inspection openings should be considered separately in the LOCA initiating event frequencies. Consequently, it is the conclusion of the B&WOG that the frequency of manway or inspection opening failure is small relative to the frequency of pipe break. Therefore the LOCA initiating event frequency based on large-bore pipe break can be considered representative.

3.4.4 Assumption of OTSG Tube RCS Pressure Boundary Damage

For a large-bore pipe break located in the hot leg candy cane, the thermally-induced tube loads are not expected to result in significant tube leakage (Appendix E). In addition, when breaks produce a high tube-to-shell temperature difference, at that time and for the duration of the event, the pressure difference across the tubes is small. However, for the purpose of the risk evaluation, significant OTSG tube RCS pressure boundary damage is assumed (e.g., failure of multiple tubes). This allows the risk assessment to calculate a bounding risk increase irrespective of any uncertainty in tube integrity. (Note: Appendix E provides a realistic estimate of multiple tube severs based on the historical SG tube inspection data that was not used in the evaluation of the CDF or LERF probabilities.)

Sequence 4, which impacts only CDF, requires significant loss of primary inventory via the failed OTSG tubes. Sequence 7, which results in an increase in LERF, requires a large release pathway via the failed OTSG tubes. Although failure of the OTSG primary-to-secondary pressure boundary is considered unlikely, the risk evaluation will assign a conservative value of 1.0 to this conditional probability.

The assumption of significant tube leakage for this event is conservative. If a large break in the upper hot leg is postulated, a substantial steam generator tube-to-shell temperature difference can be generated between 12 and 15 minutes after break initiation. This temperature difference can create high OTSG tube loads that may cause some tubes to exceed elastic strain limits. Unflawed tubes may yield and deform slightly, but their function as a primary-to-secondary isolation boundary will not be compromised.

However, if an unplugged tube has a significant undetected flaw, its ability to maintain the integrity of the effective boundary isolation is less assured. The type and location of the flaw as well as its position within the steam generator are all critical to its performance in the long term. Even so, it is likely that the critical flaw size would be detected with standard SG tube inspection techniques prior to the point when the large-bore pipe break loads would challenge these tubes. Furthermore, the steam generator integrity programs, through implementation of NEI 97-06 (see Section 4.0), provide assurance that a large quantity of undetected significant flaws is unlikely.

The OTSG tube differential temperature estimates are also conservative because they are based on ECCS water temperature of 35 to 40°F. In fact, this temperature represents a Technical Specification limit. Actual ECCS water temperature is considerably greater than this due to conditions such as BWST tank heating in cold climates and relatively warm ambient air temperatures in warm climates.

Therefore, the assumption that multiple tubes would fail under large-bore pipe break conditions is very conservative. Nonetheless, significant primary-to-secondary leakage is assumed for these scenarios, so that the risk estimate will bound any uncertainty associated with SG tube integrity.

3.4.5 Secondary Side Isolation Failure

For the OTSG tube rupture to have an impact on CDF or LERF, there must also be an isolation failure on the secondary side. For the ΔCDF sequence (sequence 4), there must be a leakage path for primary inventory through the secondary side. For the ΔLERF sequence (sequence 7), there must be a pathway for release. Unless there is coincident failure of secondary side isolation, there is no driving force (i.e., ΔP) for primary-to-secondary leakage through the failed OTSG tubes. Due to low RCS pressure (and decreasing due to systems providing RB energy removal) the ΔP between the primary and secondary of the faulted OTSG will approximate a rapid asymptotic approach toward equilibrium at atmospheric pressure. Because of this, any sustained tube leakage will occur at relatively low flow rates. In addition, for those plants that have secondary plant protection systems that isolate steam and feedwater systems on low SG pressure, e.g., 600 psig, isolation of a secondary leak will likely occur early in the transient.

For the postulated event of a large-bore pipe break such as a double-ended break of a hot leg, reactor coolant (RC) subcooled margin (SCM) will be lost within seconds following event initiation. EOPs will, based on loss of SCM, direct operators to trip RC pumps, initiate full ECCS flow, verify core flood tanks (CFTs) discharge, and ensure RB spray and other appropriate RB cooling systems are operating. In the postulated situation, ECCS will be at full flow, CFTs will have fully discharged with RCS and RB pressures initially equilibrating at about 50 psig; RB spray and other RB cooling systems will be in operation. These are classic indications of a LBLOCA. Therefore, with full ECCS flow rates being provided and OTSG pressures collapsing near to RCS pressure, there is clearly no need for OTSG operation to augment core energy removal beyond that being automatically transferred to the RB. Hence, this rapid and near complete OTSG depressurization will lead to OTSG isolation. For those plants having secondary plant protection systems (e.g., EFIC), secondary side isolation will be achieved automatically when OTSG pressure drops below predetermined values. The automatic isolation is verified and confirmed via operator action in accordance with plant procedures. For all plants, recurrent training reinforces the need to mitigate upsets in plant processes. Therefore, operations personnel, including control room and technical support center staff, will address these plant conditions and isolate OTSGs, even in the absence of installed secondary plant protection systems. This is reinforced by plant operations guidance that isolates OTSGs following recovery from a LBLOCA. Once the OTSGs are isolated, the flow of consequential tube leakage through the secondary side would be terminated.

In the postulated sequences, consequential failure of OTSG tubes is assumed to occur along with independent failure of secondary side isolation. If there is significant primary-to-secondary leakage due to such an occurrence, plant operations personnel will be alerted to the situation by an uncontrolled increase in OTSG level or by radiation monitors that may detect radioisotopes in the reactor coolant passing through the secondary side. Isolation of the OTSGs, i.e., the secondary side, will then occur and the flow of reactor coolant through these lines will be terminated. Since RCS pressure rapidly decreases and remains low, MSSV failure is unlikely for the postulated scenario.

For the largest break sizes, such as the double-ended guillotine break, the MSSVs will not be challenged. For break sizes less than that, some safety valves may initially open in response to reactor trip, but there would not be cycling such as might occur for small breaks and other transients. For the postulated upper hot leg break sequences, the secondary side pressure will drop to below 50 psig and remain there. It is unlikely that the safety valves would remain failed open at these pressures. It is very rare for a safety valve to fail to reclose all the way down to low pressures; usually when a safety valve failure is categorized "failure to reclose," it actually reclosed at some lower than desired pressure. The main steam safety valves are therefore expected to reclose before complete depressurization, i.e., to pressures less than 50 psig. When the OTSG experiences the high tube-to-shell differential temperature (that may induce tube rupture), the secondary pressure will already be below 50 psig. Therefore, there is no possibility of dependent failure due to primary water passing through the safety valves and contributing to their failure rate.

For this risk analysis, a probability of 0.01 has been assigned for failure of secondary isolation. This is a conservative value based upon secondary side valve failure probabilities in the B&WOG PRAs and engineering judgment, and considers human performance as supported by plant integrated emergency drills.

3.4.6 Operator Recovery Action Before Sump Depletion

This failure probability involves failure of operator recovery before the usable RCS inventory in the reactor building sump is depleted via the ruptured SG tubes. This failure probability only applies to the CDF sequence (sequence 4).

The potential loss of inventory will occur following a period of operation in the ECCS recirculation phase (see Section 3.4.2.1 for additional details). The time required to deplete the primary inventory via the failed OTSG tubes will depend upon their associated leak rate and the secondary side leak rate (downstream of the isolation failure). Pressures on both the primary and secondary side of the OTSG will be low (approaching an equilibrium pressure near atmospheric). This, in conjunction with resistance to flow of the leak path through the secondary side, will reduce flow rates through this path to relatively small values when compared to those being returned to the RB sump via the hot leg break and RB spray. The respective elevations of the competing flow paths may also play a role. Loss of sump inventory and subsequent ECCS pump failure will be a slow process. Hence, there will be adequate time for operator action to isolate the faulted SG, throttle back ECCS pumps, and/or replenish primary inventory. Appendix E provides additional information on the timing sequences.

Operations staff, including control room and technical support center personnel, receive recurrent training on cognitive skills that includes post-LOCA recovery diagnostics. This includes the need to monitor available RCS injection sources with emphasis on the BWST and RB sump inventories. Decreasing level in the RB sump will prompt operations personnel to consider and institute measures to commence makeup to the BWST.

In the absence of initial secondary side isolation, continuing prompts for secondary side isolation will occur as the quantity of RCS inventory lost through the failed OTSG tubes increases. This reactor coolant will continue to affect OTSG level and pass through the secondary side where radiation monitors may detect radioisotopes. This will alert plant operations personnel to continue efforts to isolate the SGs and terminate the flow of reactor coolant through these lines. Secondary side isolation also terminates the loss of RC from the RB sump.

For sequence 4, operator recovery opportunities include isolation of the secondary side leakage and replenishment of the primary inventory. Also, the B&WOG Emergency Operating Procedures Technical Bases Document, Revision 10 [9], includes guidance to throttle low pressure injection (LPI) flow to maintain minimum SCM during recovery from LOCAs or to manage pump NPSH margins. When fully implemented, this guidance provides for reducing ECCS flows for break sizes less than full double-ended guillotine, thus reducing flow rates through failed tubes (as well as reducing tube load). The lower the secondary side leak rate, the longer the recovery time will be before onset of core damage.

A conservative human error probability (HEP) of 0.1 is assumed for these operator actions. Utility programs such as licensed operator training and integrated emergency drills ensure that the assumed HEP will continue to be conservative.

3.4.7 Probability of Independent ECCS Recirculation Failure

For the LERF sequence (sequence 7), there must be an independent failure of ECCS recirculation, conditional upon success of ECCS injection. This is most likely to occur due to failure to successfully switchover the source for LPI pump suction from the BWST (injection mode) to the reactor building sump (recirculation mode). Based on a review of the B&WOG PRAs, a conservative probability for late failure of ECCS is 0.05.

3.4.8 Conditional Probability of Large Release

The conditional probability of a large release applies to the LERF sequence (sequence 7). Sequence 7 is a LOCA-induced SGTR, with secondary side isolation failure. There is a successful ECCS injection phase and depletion of the BWST. However, "early" core damage is assumed to occur at about 35 minutes after event initiation because of an independent failure of ECCS (see Section 3.4.7) that causes a failure to establish low pressure recirculation (probably due to failure of suction switchover to the RB sump). For a "large" release to occur, there must be a large unscrubbed release pathway via the secondary side or BOP to the atmosphere.

LERF is possible due to the assumed SGTR. The tube rupture is assumed to occur between 12 and 15 minutes after event initiation (see Appendix A) after the RCS refilled. The RCS inventory above the top of the core must be boiled off before core damage occurs. Therefore, primary system fluid will be leaking out of the ruptured OTSG tubes into the secondary side for approximately 20 minutes before adequate NPSH could be lost when a large number of SG tubes are postulated to fail. This RCS inventory provides substantial water levels in the secondary side for scrubbing, even if feedwater has been isolated.

The location of the failed secondary side isolation is also a factor. It is unlikely that an MSSV is stuck open in this scenario (see Section 3.4.5). It is much more likely that the isolation failure involves another path. Leaks can occur through the turbine bypass valves (TBVs), turbine-driven emergency feedwater pump steam supply valves, and atmospheric dump valves (ADVs should not be aligned). Leaks through ADVs and turbine-driven emergency feedwater pumps will discharge to the atmosphere, while leaks through the TBVs will discharge to the condenser. However, all of these pathways have additional valves for isolation. Use of these isolation methods would follow an alert to the operations staff that RC is flowing through the secondary side piping. Such alerts would be provided by rising SG levels or radiation monitors that would detect radioactive isotopes in the RC. Also, in this situation, core damage has occurred, hence, severe accident guidance may be invoked. This guidance has as its basic objectives cooling the overheated core, maintaining remaining fission product barriers, and minimizing release of fission products to the environment. Emphasis is placed on monitoring the fission product boundaries, including the OTSG tubes; hence, the RC (i.e., as steam accompanied by gases) flowing through the secondary piping would be detected by radiation monitors, and by other means depending upon plant-specific severe accident guidance. This would lead to isolation of the OTSGs, thus terminating the release.

Low primary system pressures will limit the driving force for the flow of fission products out the secondary side. Water present on the secondary side, either from feedwater or deposited by the SGTR, will provide particulate scrubbing. Secondary side pathways via the BOP will be circuitous and/or scrubbed by water present in the BOP. Consequently, most particulates are likely to be deposited in water or on surfaces before getting out to the atmosphere.

A conservative value for the conditional probability of large release of 0.1 is assumed, based upon the likelihood of scrubbing by water in the secondary side, additional isolation opportunity, and/or fission product deposition in the BOP. This value is consistent with conditional LERF values used for other SGTR sequences in the B&WOG PRAs.

3.4.9 Calculation of ΔCDF and ΔLERF

Tables 3-2 and 3-3 show the quantification of the PRA sequences developed above. These tables represent the potential risk increase (in terms of CDF and LERF) associated with not explicitly including thermal loads from the upper hot leg large-bore RCS pipe break in the OTSG design basis. In estimating the risk, it was conservatively assumed that the thermal loads caused by the large-bore pipe break would result in significant leakage through the OTSG tube RCS pressure boundary. This assumption was made in order to bound any uncertainty in the OTSG tube structural safety margins for this event.

(Note that Section E.2.4 of Appendix E contains a realistic probability of one or more tube severs based on the historical tube flaw distributions.) Even with the assumption that OTSG tube failure resulting in significant leakage is a certainty, the ΔCDF is less than 8 x 10^{-10}/year, and the ΔLERF is less than 4 x 10^{-11}/year. Relative to the guidelines in RG 1.174, this is considered a "very small" risk increase.

Table 3-4 summarizes the various conservatisms used in this risk analysis. The table illustrates the bounding nature of these risk estimates. This ensures that the incremental risk (i.e., ΔCDF and ΔLERF) associated with possible loss of OTSG tube integrity due to LOCA-induced thermal loads has been conservatively estimated, and bounds the risk impact of the proposed licensing basis change.

3.4.10 PRA Sensitivities

Conservative values were chosen for the PRA parameters used in this analysis. However, in this section, a sensitivity analysis is performed on two aspects of the PRA analysis where inherent conservative is difficult to demonstrate. This includes examining the effect of using large release frequency (LRF) as a metric instead of LERF in Section 3.4.10.1. Section 3.4.10.2 examines the effect of using a more pessimistic initiating event frequency for LOCA of the 36-inch hot leg pipe. Section 3.4.10.3 considers the use of a realistic probability for induced tube rupture, instead of the overly-conservative assumption of conditional probability of 1 for the consequential tube rupture.

3.4.10.1 Use of Large Release Frequency (LRF) as a Metric

LRF is not a required risk metric from RG 1.174, but it is included in the sensitivity analysis to provide assurance that the conclusions are not over-reliant on the definition of LERF, and the distinction between early and late release.

The ΔLRF is the sum of the ΔCDF and ΔLERF sequences from Tables 3-2 and 3-3. The ΔLERF (sequence 7) is obviously included in ΔLRF. In addition, the ΔCDF (sequence 4) from Table 3-2 has now been included in ΔLRF; it was previously excluded from ΔLERF because it involved late core damage. In that sequence the release occurs only after ECCS failure from depletion of sump inventory through the SGTR with an unisolated secondary side. For the ΔCDF sequence in Table 3-2 to contribute to ΔLRF, it must be appended with the conditional probability of large release (0.1). This accounts for the probability of a large unscrubbed release pathway to the environment. Scrubbing of iodine radioisotopes and particulates will likely be provided by the ECCS water deposited in the secondary side by the SGTR (see Section 3.4.8). The base case ΔLRF (derived from Tables 3-2 and 3-3) is shown in Table 3-5.

3.4.10.2 Large Bore Pipe Rupture Frequency

The base analysis uses the Beliczey and Schulz correlation from NUREG/CR-5750 to determine the initiating event frequency for rupture of a 36-inch large-bore pipe (see Section 3.4.3.1). The base case initiating event frequency for rupture of the 36-inch pipe (8×10^{-7}/year) is 20% of the initiating event frequency that the NUREG derives for all LBLOCAs in a PWR (4×10^{-6}/calendar-year). This is reasonable because the 36-inch pipe is a subset of the pipe sizes that are considered in the LBLOCA category of the NUREG (all 8 inch and larger pipes in the RCS pressure boundary). Furthermore, the NUREG shows that the likelihood of failure decreases proportionately as the pipe size increases.

The NUREG also reports the 95% value for the LBLOCA frequency (any 8 inch or larger RCS pipe) of 1×10^{-5}/calendar-year. The 36-inch portion of this would be about 2×10^{-6}/year. For conservatism, the sensitivity analysis uses the 95% value of the entire LBLOCA frequency, or 1×10^{-5}/year. The results are shown in Table 3-6.

3.4.10.3 Conditional Probability of OTSG Tube Rupture

Appendix E contains a realistic assessment of the conditional probability of OTSG tube failure given the postulated LOCA; however, Appendix E has not made a judgment about how many OTSG tube severs would be a "large release" or would cause failure of ECCS, if the secondary side isolation fails indefinitely. For this sensitivity analysis, the probability of one or more severed tubes from Appendix E will be used, which is a conditional probability of 0.041 that there will be an induced tube rupture from the postulated LOCA. Table 3-6 shows the results.

3.4.10.4 Results of PRA Sensitivity

The results of the PRA sensitivity analyses show that the conclusions are robust. The incremental risk from the postulated LOCA-induced SGTR scenarios is small.

Table 3-2 ΔCDF (Sequence 4)

Failure	
LOCA in hot leg candy cane	8 x 10^{-7}/year
Significant OTSG tube damage (e.g., failure of multiple tubes)	1.0 (conservative)*
Secondary isolation fails	0.01
Recovery actions fail to prevent sump depletion before ECCS recirculation failure/ core damage	0.1
	<8 x 10^{-10}/year

* Appendix E shows the probability of one or more tube failures to be 0.041, and four or more tube failures to be less than 10^{-6}.

Table 3-3 ΔLERF (Sequence 7)

Failure	
LOCA in hot leg candy cane	8 x 10^{-7}/year
Significant OTSG tube damage (e.g., failure of multiple tubes)	1.0 (conservative)*
Secondary isolation fails	0.01
ECCS recirculation failure	0.05
Conditional probability of large release	0.1
	<4 x 10^{-11}/year

* Appendix E shows the probability of one or more tube failures to be 0.041, and four or more tube failures to be less than 10^{-6}.

Table 3-4 Summary of Conservatisms in PRA Calculations

ELEMENT OF RISK ANALYSIS	CONSERVATISMS	APPLIES TO
Estimate of Large-bore Pipe LOCA Frequency	• Bounding estimate of break frequency based on all 36" RCS pipe • Includes all ruptures, even those too small to cause SG challenge	Sequences 4 & 7
SG Tube Pressure Boundary Damage	• Bounded by assumption that significant leakage occurs (P=1.0) • Significant tube leakage is not expected (See Section E.2.4) • Thermal-hydraulic analyses that compute differential temperatures are bounding, but applied to all conditions (e.g., Tech. Spec. minimum ECCS water temperature used, main feedwater terminated at t=0, etc.)	Sequences 4 & 7
Secondary Isolation	• Low primary and secondary side pressure make MSSV failure unlikely • No liquid challenge to MSSVs • Operator guidance/training addresses necessary actions • Conservative HEP	Sequences 4 & 7
Prevent Depletion of ECCS Sump	• Low driving force (ΔP) for loss of inventory (See Section E.3) • Long time before loss of ECCS (See Section E.4) • BWST makeup available	Sequence 4
Failure of Low Pressure ECCS Recirculation	• Bounding failure rate from B&WOG PRAs	Sequence 7
Conditional Probability of Large Release	• Low primary system pressures limit the flow rate of fission products to the secondary side (See Section E.3.3) • The secondary side is a circuitous pathway to the environment • Pathway is likely to be wet, providing scrubbing	Sequence 7

Table 3-5 ΔLRF

Failure	(Sequence 4)	(Sequence 7)
LOCA in hot leg candy cane	8 x 10^{-7}/year	8 x 10^{-7}/year
Significant OTSG tube damage (e.g., failure of multiple tubes)	1.0 (conservative)	1.0 (conservative)
Secondary isolation fails	0.01	0.01
Recovery actions fail to prevent sump depletion before ECCS recirculation failure/ core damage	0.1	n/a
ECCS recirculation failure	n/a	0.05
Conditional probability of large release	0.1	0.1
	<8 x 10^{-11}/year	**<4 x 10^{-11}/year**
Total ΔLRF	**<1.2 x 10^{-10}/year**	

Table 3-6 PRA Sensitivity: ΔLRF

		Large Bore Pipe Break Frequency	
Conditional Probability of Tube Rupture		**8 x 10^{-7}/year (base case)**	**1 x 10^{-5}/year**
1.0 (base case)		1.2 x 10^{-10}/year	1.5 x 10^{-9}/year
0.041		4.9 x 10^{-12}/year	6.2 x 10^{-11}/year

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4.0 Implementation and Monitoring (Element 3)

Each B&WOG plant has performance monitoring programs that meet the requirements of Element 3 of Regulatory Guide 1.174. These programs will ensure that no adverse degradation occurs because of the proposed changes to the licensing basis, and that the performance of the SSCs that are relied upon to justify the proposed change to the licensing basis will be maintained. Existing plant programs, such as the Maintenance Rule, will track and trend equipment performance and provide early indication in case of unanticipated degradation in the reliability or availability of SSCs related to the proposed change.

The risk evaluation performed in Section 3.4 (i.e., estimation of ΔCDF and ΔLERF) relies on certain assumptions concerning the integrity of the RCS and the low likelihood of a LOCA in the large-bore hot leg piping. There are a variety of programs currently in place that monitor the condition and integrity of the RCS. These programs verify that changes in condition have not occurred that may impact the LOCA initiating event frequency. The programs applicable to the large-bore pipe break initiating event frequency include:

- The ASME Section XI inservice inspection (ISI) program, which is responsible for periodic examination of RCS welds, bolting, and component supports, and pressure testing of the RCS.

- Technical Specification leakage limits, which require the plants to closely monitor RCS leakage. If leakage is detected, a root cause evaluation is performed in accordance with each plant's 10 CFR 50, Appendix B requirements and corrective measures are taken to prevent future occurrences. All the B&WOG plants have Technical Specifications, which require plant shutdown in the event of excessive RCS leakage.

- The NRC's Oversight Program, in which primary system leakage is one of the Performance Indicators.

- 10 CFR 50.65 (Maintenance Rule), which requires that primary system functions be monitored for reliability and availability. The B&WOG plants have functional performance criteria for RCS integrity. If RCS leakage Technical Specification limits are exceeded, the RCS would go into Maintenance Rule category a(1) and a root cause analysis would be performed, a performance improvement plan and goals would be developed, and additional monitoring would be performed until the system performance is shown to be acceptable.

These programs help ensure the integrity of the RCS and preserve the low probability of a break in the large-bore piping.

The risk evaluation performed in Section 3.4 also relies on certain assumptions concerning the reliability and availability of plant equipment. Monitoring of SSC performance, including SSCs that may be used to mitigate this event, is included in the scope of the Maintenance Rule. The Maintenance Rule ensures that there will be plant-specific performance criteria for these SSCs, including the valves important to secondary side isolation and ECCS recirculation. Decreasing reliability or availability, which may affect risk, will be identified by the Maintenance Rule and corrected. These SSCs are also subject to other plant programs, such as the valve programs, inservice testing, and Technical Specifications.

In addition, any unforeseen impact of the proposed licensing basis change upon steam generator integrity will be identified by the utilities' steam generator integrity programs. The B&WOG utilities have programs that will ensure continued steam generator integrity. The programs include the following steps, which satisfy the monitoring, trending, and feedback requirements of RG 1.174:

1. Tube Inspections

Tube inspections monitor defects that may be present in the steam generator, identify tubes containing defects, and estimate the size of these defects. Non-destructive examinations are mandated by plant Technical Specifications.

2. Condition Monitoring

The B&WOG plants perform condition monitoring assessments after tube inspections to verify that the tubes would have maintained structural integrity and accident leakage integrity for the most limiting postulated design basis accident. The probability of a tube rupture during the operating cycle prior to the inspection must be shown to have been low.

3. Operational Assessments

The B&WOG plants perform operational assessments to project the end-of-cycle condition of the steam generators and verify that the projected leakage during the forthcoming cycle of operation is acceptable. These assessments must conclude that the steam generators are projected to maintain their structural integrity and accident leakage integrity through the last day of the forthcoming cycle for the most limiting postulated design basis accident. The probability of a tube rupture during the forthcoming cycle must be shown to be low.

4. Tube Plugging or Repairs

The B&WOG plant Technical Specifications require that steam generator tubes found to be unserviceable during inspections be removed from service or repaired prior to plant start-up. Plugging and repair methods are developed, qualified, and implemented in accordance with the applicable provisions of the ASME code and 10 CFR 50, Appendices A and B.

5. Corrective Actions

All of the B&WOG plants have corrective action programs under which any significant steam generator problems must be identified and tracked. These programs also require that corrective actions for the problems be identified. For example, if condition monitoring failed to confirm that the steam generator performance criteria were satisfied, the following actions would be required prior to plant start-up from the inspection outage:

- assessment of causal factors (for example, a new or unexpected degradation mechanism or defect type, insufficient sample sizes for tube inspection, unexpectedly high defect growth rates, less than expected performance of NDE techniques and/or personnel, or deficiencies in predictive methodology for operational assessment), and

- implementation of corrective actions.

6. Steam Generator Leakage Monitoring

The B&WOG plants have Technical Specifications, which require steam generator leakage monitoring, and specify leakage limits. The goal of the B&WOG plant leakage monitoring is to provide clear, accurate, and timely information on operational leakage to allow timely remedial actions to be taken to prevent tube rupture or burst, or to facilitate the mitigation of any tube rupture or burst event.

The existing B&WOG plant steam generator monitoring and maintenance programs described above are among those that help ensure that unanticipated degradation of steam generator performance related to the proposed licensing basis change will be identified early and corrected. It is also notable that all of the B&WOG utilities have indicated they *intend to comply with the steam generator program requirements described in* NEI 97-06 [10].

The analyses performed and documented in Appendices E and F of this Topical Report to demonstrate compliance to 10 CFR 50.46 and Part 100 or 50.67 use several key parameters or assumptions that require confirmation in the future to support the conclusions drawn in this Topical Report. The two commitments, which are reiterated in Appendix G, are:

- Confirming that the fuel pin cladding does not rupture for the hot leg U-bend (i.e., "candy cane") break to support the Appendix F conclusions and
- Showing LOCA cooldown-induced consequential SGTR leakage from as-found flaws is less than or equal to the leakage rate predicted by the four free span tube ruptures used in the Appendix E analyses.

Significant changes in the ECCS analysis methods, ECCS flow rates, or fuel designs could challenge the criteria for no fuel pin rupture. Future LOCA analyses will evaluate and confirm the validity that no rupture occurs for the hot leg U-bend break. The leakage rates determined in Appendix E from four free span tube ruptures is bounded by predicted leakage from the as-found SG tube flaws following each outage in which steam generator tube examinations are conducted. This commitment may be included in a Licensing Commitment or Technical Specification change to ensure that if tube degradations change in the future, the extent of condition cannot evolve to the point where the conclusions formed in this Topical Report are invalidated.

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5.0 Summary and Conclusions

This Topical Report presents a technical justification for changing the licensing basis of B&W-designed nuclear power plants. The requested change to the licensing basis is to establish a risk-informed basis for the acceptability of postulated thermal loads on OTSG tubes, tube repair products, and tube-to-tubesheet joints induced by a LOCA in the large-bore piping of the RCS upper hot leg. The justification for the requested change is that the OTSG thermal loads from a large-bore pipe break in the upper RCS hot leg (including OTSG upper manways and inspection openings) present a "very small" risk to public health and safety per the acceptance guidelines of RG 1.174. The risk-informed evaluation presented in this report demonstrates the acceptability of thermal loads on OTSG tubes, tube repair products and tube-to-tubesheet joints from a break in the upper hot leg large-bore piping. Therefore, the acceptability of OTSG thermal loads will be based on this report, and on deterministic evaluation of the previously analyzed limiting accident, which is either a LOCA in RCS attached piping or MSLB.

The justification provided for the proposed licensing basis change has been prepared in accordance with the guidance of Regulatory Guide 1.174, and constitutes a risk-informed approach. The principles from RG 1.174 have been demonstrated for the proposed change:

- Meets current regulations (including 10 CFR 50.46 and 10 CFR 100 or 50.67)
- Is consistent with defense-in-depth philosophy
- Maintains sufficient safety margins
- Increase in risk is small
- Impact will be monitored using performance measurement strategies

The contribution to plant risk (i.e., ΔCDF and ΔLERF) from the postulated LOCA-induced SGTR scenarios has been estimated and it has been shown that they are not risk-significant using the probabilistic and deterministic framework of RG 1.174. PRA sequences have been developed that conservatively assume LOCA-induced steam generator tube rupture due to breaks in large-bore RCS piping. Significant primary-to-secondary OTSG leakage is assumed for these sequences, so that the risk estimate will bound any uncertainty associated with SG tube integrity. The estimated ΔCDF and ΔLERF associated with the postulated LOCA-induced steam generator tube rupture are shown to be very small relative to the acceptance guidelines in RG 1.174 and defense-in-depth principles are shown to be preserved. This includes:

1. Determination of the maximum tube-to-shell temperature differences for any LOCA break location or size (Appendix A),
2. Consideration of steam generator manways and hot leg piping integrity (Appendices B and C),
3. Evaluation of the general design criteria (Appendix D),
4. Demonstration of long-term core cooling (Appendix E),
5. Showing that the dose is bounded by either SGTR or other CLPD LOCA transients (Appendix F), and
6. Summarizing future commitments to ensure the conclusions drawn in the report remain valid (Appendix G).

These results demonstrate that OTSG thermal loads from hypothesized upper hot leg large-bore pipe breaks (including OTSG upper manways and inspection openings) have been adequately addressed. Therefore use of the limiting thermal loads from other analyses (attached pipe LOCA and MSLB) is appropriate for meeting the requirements of the licensing basis for OTSG tubes, tube repair products, and tube-to-tubesheet joints.

It has been demonstrated for the B&W-designed plants that the proposed change to the licensing basis will not adversely impact risk to the health and safety of the public, and that NRC approval is justified.

6.0 Certification

Revision 1 of BAW-2374 contained certification signatures that confirmed that revision of the Topical Report was accurate and complete.

BAW-2374 Main Report: Risk-Informed Assessment of OTSG Thermal Loads			
Prepared by:		Reviewed by:	
	3-8-01		3-8-01
RS Enzinna, Sr. Principal Engineer, Risk & Reliability Analysis	Date	SH Levinson, Advisory Engineer, Risk & Reliability Analysis	Date

Appendix A: Evaluation of Tube-to-Shell Temperature Differences			
Prepared by:		Reviewed by:	
	3/8/01		3/8/01
JA Klingenfus, Sr. Supervisory Engineer, Analysis Services	Date	DR Page, Engineer, LOCA Methods	Date

Appendix B: Evaluation of Manway/Inspection Opening Failures			
Prepared by:		Reviewed by:	
	3-8-01		3/8/01
SH Levinson, Advisory Engineer, Risk & Reliability Analysis	Date	SB Brown, Manager, Steam Generator Engineering	Date

Appendix C: Evaluation of RCS Hot Leg Piping			
Prepared by:		Reviewed by:	
	3-8-01		3-8-01
MA Rinckel, Project Engineer, B&WOG Generic License Renewal	Date	SH Levinson, Advisory Engineer, Risk & Reliability Analysis	Date

Appendix D: Evaluation of General Design Criteria			
Prepared by:		Reviewed by:	
	3-8-01		3/8/01
MW Epling, Project Manager, B&WOG Licensing Working Group	Date	DJ Firth, Manager of Owners Group Services	Date

Approved by:	
	3/8/01
GK Wandling, Project Manager, B&WOG Steam Generator Committee	Date

The certification signatures given on the next two pages confirm that the modifications and additional information included in Revision 2 of BAW-2374 is accurate and complete.

Modifications to BAW-2374 Main Report: Risk-Informed Assessment of OTSG Thermal Loads Except Sections 3.4.9 and 3.4.10			
Prepared by:	12/21/06	Reviewed by:	12/21/06
JA Klingenfus, Advisory Engineer, Reactor Operation and Accident Analysis	Date	DR Page Blair, Supervisor, Reactor Operation and Accident Analysis	Date

Modifications to BAW-2374 Main Report: Risk-Informed Assessment of OTSG Thermal Loads Sections 3.4.9 and 3.4.10			
Prepared by:	12/20/06	Reviewed by:	12/20/06
RS Enzinna, Advisory Engineer, Risk & Reliability Engineering	Date	SH Levinson, Advisory Engineer, Risk & Reliability Engineering	Date

Modifications to Appendix A: Evaluation of Tube-to-Shell Temperature Differences			
Prepared by:	12/21/06	Reviewed by:	12/21/06
JA Klingenfus, Advisory Engineer, Reactor Operation and Accident Analysis	Date	DR Page Blair, Supervisor, B&W LOCA Analysis	Date

Modifications to Appendix B: Evaluation of Manway/Inspection Opening Failures & Appendix C: Evaluation of RCS Hot Leg Piping			
Prepared by: for JEFF BROWN	12/21/06	Reviewed by:	12/21/06
J Brown, Advisory Engineer, Mechanical Equipment	Date	DR Page Blair, Supervisor, Reactor Operation and Accident Analysis	Date

Appendix E, All Sections Except Section E.2: Long-Term Core Cooling Following a HL U-Bend Break			
Prepared by:	12/21/06	Reviewed by:	12/21/06
JA Klingenfus, Advisory Engineer, Reactor Operation and Accident Analysis	Date	DR Page Blair, Supervisor, Reactor Operation and Accident Analysis	Date

Appendix E, Section E.2: Long-Term Core Cooling Following a HL U-Bend Break			
Prepared by:	12/20/2006	Reviewed by:	12/20/06
J Begley, Advisory Engineer, Steam Generator Engineering	Date	D Costa, Advisory Engineer, Steam Generator Engineering	Date

Appendix F, Sections F.1 – F.3: Dose Consequences Following a HL U-Bend Break Dose Consequences Study			
Prepared by:	12/20/06	Reviewed by:	12/21/06
ME Byram, Principle Engineer, Reactor Operation and Accident Analysis	Date	DR Page Blair, Supervisor, B&W LOCA Analysis	Date
Appendix F, Sections F.4 & F.5: Dose Consequences Following a HL U-Bend Break			
Prepared by:	12/21/06	Reviewed by:	12/21/06
JA Klingenfus, Advisory Engineer, Reactor Operation and Accident Analysis	Date	DR Page Blair, Supervisor, B&W LOCA Analysis	Date

Appendix G, Sections G.1 and G.3 Summary of Future Commitments			
Prepared by:	12/21/06	Reviewed by:	12/21/06
JA Klingenfus, Advisory Engineer, Reactor Operation and Accident Analysis	Date	DR Page Blair, Supervisor, Reactor Operation and Accident Analysis	Date
Appendix G, Section G.2: Summary of Future Commitments			
Prepared by:	12/20/2006	Reviewed by:	12/20/06
J Begley, Advisory Engineer, Steam Generator Engineering	Date	D Costa, Advisory Engineer, Steam Generator Engineering	Date

Appendix H: Glossary of Acronyms			
Prepared by:	12/21/06	Reviewed by:	12/21/06
JA Klingenfus, Advisory Engineer, Reactor Operation and Accident Analysis	Date	DR Page Blair, Supervisor, Reactor Operation and Accident Analysis	Date

Approved by:	
	12/21/06
RJ Schomaker, Project Manager, PWROG Analysis Committee	Date

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7.0 References

[1] Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," U.S. Nuclear Regulatory Commission, July 1998.

[2] B&W Topical Report BAW-10027, "Once-Through Steam Generator Research and Development Report (Nonproprietary Version of BAW-10002)," April 1971.

[3] Draft Regulatory Guide 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes," August 1976.

[4] B&W Topical Report BAW-10146, "Determination of Minimum Required Tube Wall Thickness for 177-FA Once-Through Steam Generator," October 1980.

[5] B&W Topical Report BAW-1847, Rev. 1, "Leak-Before-Break Evaluation of Margins Against Full Break for RCS Primary Piping of B&W Designed NSS," September 1985.

[6] NRC Safety Evaluation of B&W Owners Group Reports Dealing with Elimination of Postulated Pipe Breaks in PWR Primary Main Loops, dated December 12, 1985.

[7] NUREG-0933, "A Prioritization of Generic Safety Issues," U.S. Nuclear Regulatory Commission, April 1999.

[8] NUREG/CR-5750, "Rates of Initiating Events at U. S. Nuclear Power Plants: 1987 – 1995," February 1999.

[9] AREVA Doc. No. 74-1152414-10, "Emergency Operating Procedures Technical Bases Document," Revision 10, December 2005.

[10] NEI 97-06, Rev. 2, "Steam Generator Program Guidelines," May 2005.

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Appendix A

LOCA Thermal-Hydraulic Evaluation of Maximum Tube-to-Shell Temperature Differences

The margin bars denote changes from Revision 1

Table of Contents

List of Tables

List of Figures

LOCA Thermal-Hydraulic Evaluation of Maximum Tube-to-Shell Temperature Differences

A.1 Introduction and Background

A postulated loss-of-coolant accident (LOCA) is one of the faulted-condition design transients considered to determine the potentially bounding loads for steam generator component design. The dynamic and jet impingement loads from full area guillotine breaks in the large-bore reactor coolant system (RCS) pipes were originally used in structural analyses for the once-through steam generator (OTSG). These breaks have been excluded from the design calculations by taking credit for Nuclear Regulatory Commission (NRC) approved leak-before-break (LBB) qualifications in BAW 1847 [A-1] on the large-bore RCS piping. The component design parameters have been subsequently evaluated by using loads calculated for the largest postulated attached pipe breaks, including the pressurizer surge line, core flood lines, and decay heat drop line. The dynamic loads from these smaller break sizes produce reduced loads that have been credited in a variety of licensing analysis applications.

Framatome ANP and the B&W Owners Group (B&WOG) implicitly credited LBB considerations in determining the bounding tube-to-shell temperature differences from which thermal loads on the steam generator tubes were calculated. Therefore, because the tube thermal loads from a non-mechanistic break in the upper hot leg large-bore pipe have not been rigorously analyzed, they must be included in the consideration of this Regulatory Guide 1.174 risk-informed submittal. This appendix is included to provide the thermal-hydraulic information necessary for that consideration.

In support of this risk-informed submittal, an evaluation of the expected tube-to-shell thermal consequence from any break in the large-bore RCS piping was completed. This evaluation postulated a non-mechanistic break in any RCS pipe (cold leg pump discharge

(CLPD), cold leg pump suction (CLPS), hot leg, and large attached pipes) of any size up to and including a double-ended guillotine break. By reviewing the RCS thermal-hydraulic behavior following this spectrum of breaks, the worst break sizes and locations were determined, and a representative thermal-hydraulic analysis was completed to predict typical generic tube-to-shell temperature differences. These results were compared against the analyzed limiting attached pipe break (pressurizer surge line break) temperature difference to quantify how much the thermal difference will change if breaks in large-bore piping are considered. This evaluation characterized the large-bore break sizes and locations that can potentially be most severe, such that the scope of risk analysis (see Section 3.4) was appropriately focused on the large-bore pipe breaks for which steam generator thermal loads exceed existing analyses. The evaluation of the characteristic LOCA thermal consequences for all break sizes was also used to determine which attached pipe breaks are potentially limiting LOCA transients that should be used to define the steam generator (SG) thermal load design basis if this B&WOG request is granted.

A.2 RCS Evolution for the Large-Bore RCS Pipe Break Spectrum

The plant emergency core cooling systems (ECCS), consisting of the core flood tanks (CFTs), high pressure injection (HPI) pumps, and low pressure injection (LPI) pumps, activate following a LOCA to supply makeup flows adequate to refill the core and remove the core stored energy and decay heat. Once the core and reactor vessel refill with liquid, any ECCS flow that is not boiled off will refill the remainder of the RCS piping and components. This refill is limited or reduced when the liquid level reaches the break location. If the break is of sufficient size to discharge all the excess ECCS, then the refill level will be restricted to that of the break elevation.

The rate of RCS refill is closely tied to the ECCS flow rates. The CFT flow is primarily responsible for the initial core refill, but the CFTs generally empty before the reactor vessel is refilled. The pumped injection provides the ECCS flow to complete the vessel and then the RCS refill. If the break is small, it restricts the rate of RCS pressure decrease and delays the start of LPI flow. Although HPI can slowly refill the RCS, it has less potential to create the high steam generator tube-to-shell temperature differences that can result from a LBLOCA. The highest tube-to-shell temperature differences will be generated when there is significant LPI flow, but relatively high values may also be achieved with only HPI (or HPI plus makeup pumps for Davis-Besse). That is, the RCS break size must be sufficient to depressurize the RCS to pressures where significant pumped-ECCS flow is delivered.

The refill rate and maximum refill level will determine the maximum tube-to-shell temperature difference. The fastest refill occurs when all ECCS pumps (2 LPI pumps and 2 HPI pumps) are operating at near runout flows. The refill rate and temperature differences are also maximized when the borated water storage tank (BWST) and emergency feedwater (EFW) temperatures are minimized (40 F for EFW, 35 to 40 F for BWST). Lower ECCS flows or higher temperatures will reduce the maximum tube-to-shell temperature difference regardless of the break size or location. (Note: In this appendix, the term tube-to-shell temperature difference is frequently used but the actual difference is calculated as the difference between the axially-averaged shell and tube temperatures, or $T_{shell\ ave} - T_{tube\ ave}$.)

In the following subsections, the RCS levels and energy transport paths are considered in estimating the maximum differences between the shell and tube average temperatures. The estimates use available analytical results to approximate the shell and tube cooldown rates and to obtain the maximum temperature difference. The approaches are fairly simple, but they attempt to consider a variety of parameter variations that can influence the slopes of two nearly parallel temperature cooldown curves. Although the absolute temperature difference may vary somewhat, the relative change in the maximum difference (increase or decrease) from analyzed cases such as the pressurizer surge line break are reasonable and reliable for determining the overall severity of the transient. These relative thermal differences can be used to determine the worst break locations and characterize limiting conditions or parameters that will cause them to be more severe.

A.2.1 Cold Leg Pump Discharge (CLPD) Break

From a core cooling perspective, a large LOCA at the inlet to the reactor vessel is a limiting event because it maximizes the ECCS flow that bypasses the core and is unavailable for core heat removal. This break size and location, however, restrict the RCS refill to the reactor vessel (RV) and the hot leg horizontal pipe, as shown in Figure A-1 for the lowered-loop plants. Break sizes large enough to discharge all the excess ECCS flow will depressurize to the containment pressure and not allow any refill into the SG tubes. Without any RCS or SG refill, the tube temperature will fall between the saturation temperatures of the primary and secondary sides. The average tube temperature will remain closely coupled to the secondary temperature because of the secondary side liquid level. The temperature of the secondary side pool also influences the SG shell average temperature. As a result, this break location will have the smallest tube-to-shell temperature difference for any class of breaks.

The maximum tube-to-shell temperature differences have not been explicitly calculated for all CLPD breaks, but they are expected to range between 50 and 150 F. The maximum temperature difference is not a strong function of break area, although the maximum difference could increase with smaller break sizes that may not totally clear the CLPS regions. The largest break sizes will empty and not allow any refill of the CLPS region or SG tubes. Smaller break sizes can have some slow refill of the CLPS or SG tubes after the ECCS inflow exceeds the break flow. This partial refill can result in a faster cooling of the thin tubes versus the thick shell metal and overall tube-to-shell temperature difference could reach the upper range for this break location.

If the break is moved from the RV inlet nozzle to the pump discharge elevation, the RCS refill is different. For this break location, the excess ECCS can spill backward through the pump and flow into the CLPS region in the intact legs. This break elevation will not affect the steam generator refill for the raised-loop plant because the tubes are above the break elevation, but it will change the SG refill for the lowered-loop plants. An upper

CLPD break for a lowered-loop plant will behave like an upper CLPS break described in the next section.

A.2.2 Cold Leg Pump Suction (CLPS) Break

A large LOCA in the cold leg between the SG exit and the reactor coolant pump (RCP) inlet is a less limiting core cooling event because there is less ECCS flow bypassed from the core. This break location does allow the CLPD regions of the RCS to refill until the excess ECCS spills backward over the RCP into the CLPS piping. For a raised loop plant, all CLPS piping is below the bottom of the SG tubes, therefore, there will not be any appreciable difference from a CLPD break.

The break location within the CLPS piping is important for the lowered-loop plants, because the RCP spillover elevation is near the middle of the SG tubes. If the break is low in the CLPS piping and the break is large in size, then there will not be any refill of the broken loop SG tubes and the tube-to-shell temperature difference will be similar to a comparably-sized CLPD break. On the other hand, the intact loop SG for a lowered-loop plant will eventually refill to near the RCP spillover elevation. This refill of the intact loop with the cold ECCS will cool the secondary side pool temperature. The intact loop SG tube temperature will eventually decrease to that of the RCS saturation temperature. As the ECCS refills the SG tubes it will boil initially and remove energy from the secondary side resulting in the convergence of the RCS and secondary side pressure and temperature in the intact loop. The secondary side cooldown will aid in cooling of the lower shell, however, the thickness of the shell will retard the rate of decline resulting in a tube-to-shell temperature difference that is expected to reach a maximum of between 195 to 215 F for the larger break sizes. If the break location were postulated at the RCP inlet, then the liquid level in the broken loop SG tubes would be similar to that of the intact loop resulting in similar thermal differences.

For the CLPS breaks, smaller break sizes may not be able to quickly decrease the RCS pressure to that of the containment building. The elevated pressure will increase the saturation temperature of the fluid in the tubes, resulting in generally lower thermal differences as the break size decreases. The decreasing temperature difference likely stops when the break size gets small enough that the ECCS can refill the RCS above the break elevation.

A.2.3 Hot Leg Breaks

A large LOCA in the hot leg at the RV exit nozzle elevation does not represent a serious challenge to core cooling because all ECCS is available for that purpose. Once the RV is refilled, any excess ECCS spills out of the hot leg break. A portion of the CLPD piping will refill, but liquid spillover backward through the RCP will not occur. Therefore, this break location will not refill the steam generator tubes and its maximum tube-to-shell temperature difference will be similar to the CLPD RV inlet nozzle break.

If the break elevation is postulated in the hot leg vertical riser section, or at an attached pipe location such as the pressurizer surge line connection, as shown in Figure A-2 for the lowered-loop (LL) plants, the CLPD regions can be refilled and excess ECCS will spill into the CLPS piping. For a raised loop plant, shown in Figure A-4, the break must be at least 5.6 ft above the RV nozzle belt centerline to begin to refill the SG tubes. For the lowered-loop plants, any hot leg break above the RCP spillover elevation will result in significant refill of the SG tubes. The maximum tube refill level for either plant design will be limited to the postulated hot leg break elevation for a break size large enough to discharge all the injected ECCS flow. Small break sizes can slowly refill above the break elevation, but the rate of refill is slow enough that the elevated RCS saturation temperature will limit the severity of the tube-to-shell temperature difference.

The extent of tube cooling is closely related to the liquid level established within the tubes and the time at which that maximum level is established. Large LOCAs will have the fastest refill, but the tube refill cannot be complete until the secondary side pool is cooled off to approximately the saturation temperature of the primary. The cold ECCS that begins to refill the hot tubes will initially boiloff rapidly and possibly carry a steam-water mixture upward through the tubes similar to a core reflood process. A high liquid level inside the tubes (which is controlled by the hot leg break elevation) will result in additional ECCS entering the SG and this will increase the rate of tube average temperature decrease. The minimum tube temperature will then approach that of the RCS saturation temperature. The secondary saturation pressure should decrease to that of the primary after the tube refill begins. The secondary depressurization will increase the rate of shell cooling, however the shell average temperature decrease will lag behind that of the tubes. The most rapid tube cooldown rate, which is given by the largest break sizes, will therefore create the highest tube-to-shell temperature difference.

If the break elevation is postulated near the top of hot leg, as shown in Figure A-3 for the lowered-loop plants, the CLPD, CLPS, hot leg and SG tube regions of the broken loop can be completely refilled, and a continuous liquid flow through the tubes can be established. This liquid throughput can cool the tube temperatures below the RCS saturation temperature, with the tubes cooling to a minimum temperature closer to the ECCS inlet temperature for high excess ECCS flow rates. The tube inlet temperature is determined by the fraction of core decay heat that is transported through the reactor vessel vent valves (RVVVs) into the upper downcomer. The RVVV flow behavior is controlled by the break location and the RCS temperature distribution that is established by the core energy transport mechanism after the RCS refills. A break near the top of the hot leg U-bend (or candy cane) has roughly a 50/50 energy flow (as well as ECCS flow) split between the hot leg versus that of the cold leg-SG flow path. A break between the top of the U-bend and the SG inlet would have a higher energy and liquid flow split going through the steam generator tubes. In general, the tube inlet temperature for those upper hot leg breaks that have liquid flow from both the hot leg and SG sides will be set by the ECCS inlet enthalpy ($h_{ECCS\ in}$) plus the enthalpy rise computed by the total instantaneous core power ($Q_{core\ total}$) divided by the total ECCS flow rate ($W_{ECCS\ total}$). In equation form this minimum tube inlet enthalpy ($h_{SG\ tube\ inlet}$) is

$$h_{SG\ tube\ inlet} = h_{ECCS\ in} + Q_{core\ total} / W_{ECCS\ total}.$$

This inlet enthalpy is both time and pressure dependent because of the variations in core power, ECCS flow rates, and ECCS suction source (i.e., BWST versus sump recirculation). Potential operator actions to throttle ECCS flows to manage core exit subcooling are yet another variable to consider for LOCAs that establish the maximum tube-to-shell temperature differences after 30 minutes.

For the largest break sizes, the maximum tube-to-shell temperature difference will occur within the first 30 minutes. Therefore, a maximum ECCS injection rate (without ECCS throttling) will result in the fastest tube refill and lowest tube inlet temperature. During the tube refill, the secondary side pool is cooled below the RCS saturation temperature. In the long term, the tube average and secondary pool temperatures will approach the tube inlet temperature. The ECCS liquid flowing through the tubes condenses steam on the secondary side and causes the secondary pressure to drop below atmospheric pressure when the secondary side is completely isolated. The secondary pool cooling will increase the rate of shell cooling, however the shell average temperature decrease will lag behind that of the tubes. The highest tube-to-shell temperature difference is produced within the first 15 minutes by the maximum ECCS flow rates. The largest breaks in the upper hot leg could produce tube-to-shell temperature differences between 330 and 375 F for the raised-loop plant depending upon the tube inlet temperature. If the tube inlet temperature is postulated to approach the ECCS inlet temperature of 35 F, then the maximum value is 375 F. The value decreases to 330 F when RVVV transport of the core energy is considered.

The maximum tube-to-shell temperature differences for the lowered-loop plants are similar but slightly smaller because the minimum ECCS inlet temperature is 40 F. These plants also use EFW to refill the secondary side to a higher level than the raised-loop plant. This higher pool level results in roughly a 20 F lower shell average temperature because of the longer section that has enhanced pool cooling. The 5 F increase in ECCS temperature plus the estimated 20 F decrease in the shell temperature will result in lowered-loop maximum temperature differences of 305 F to 350 F, depending upon the RVVV energy transport.

The tube-to-shell temperature differences obtained with the upper hot leg breaks are clearly higher than those obtained for any other break location. The maximum difference is also produced by the largest break size at a time that essentially cannot be influenced by operator actions. The maximum thermal differences should decrease with reduced break sizes because the ECCS refill rate is slower. The slower tube cooldown rate will be closer to that of the shell temperature decrease and smaller maximum thermal differences will be obtained. Also, for the smaller break sizes, the operators are instructed by the emergency operating procedures to throttle the ECCS to restrict the amount of core exit subcooling. Reduced ECCS flows will slow the tube cooling and further decrease the maximum temperature difference that can occur.

A.3 Structural Break Classifications

As described in the previous section, the spectrum of potential pipe breaks was considered to determine which break sizes and locations could result in the highest tube-to-shell temperature differences. The break locations included partial or complete severance of the large-bore piping or any attached pipes. The location of the postulated pipe break is not restricted for ECCS analyses, and any size pipe break from a tiny crack to a full double-ended guillotine is considered. Structural analyses generally postulate breaks in mechanistic locations coinciding with:

1. Terminal ends of pipes
2. High usage factors, or
3. Places where the combination of primary plus secondary stress exceed 2.4 S_m.

The analyses use the relative differences in the axial to circumferential stresses to determine which type of break, a longitudinal split or guillotine, is plausible. In general, for the B&W-designed plants, the large-bore pipe stress profiles have higher axial stresses, such that any break would be a guillotine in nature.

Structural analyses have also been performed to determine how large a crack would have to be for the leakage to be detected by the RCS leak detection system under normal operating conditions. The load from a design basis earthquake was imposed on this maximum critical crack in any RCS large-bore piping to show that it would not propagate into a full guillotine break. This approach allows the leak to be detected before the crack grows to an unstable size and give the operators time to shut the plant down safely. This leak-before-break methodology is already credited for eliminating the dynamic loads from breaks in large-bore piping. As previously described, the thermal loads were not explicitly excluded by the LBB methodology SER [A-2], so this Regulatory Guide 1.174 submittal is being made to request a risk-informed basis for the acceptability of the upper hot leg large-bore pipe break thermal loads. If the NRC grants approval for this approach, then the limiting LOCA thermal loads (like the dynamic loads) used for deterministic licensing basis analyses of OTSG tubes, tube repair products, and tube-to-tubesheet joints will be generated as a consequence of an attached pipe break.

As discussed in Section A.2, the limiting thermal loads are produced by a break located at an upper RCS elevation, which focuses the attention to the hot leg pipe connections. Thus, any attached pipe that connects to the hot leg must also be considered as a potential candidate to establish the SG design basis thermal loads. The following two tables, A-1 and A-2, give the attached pipe connections for the lowered-loop [A-3] and raised loop plants, respectively. Note that the tables also list the SG upper head manway and inspection openings, although breaks of these closures are not considered to be any more likely than a large-bore pipe break (See Section 3.4.3.2 and Appendix B).

Table A-1 Lowered-Loop Plant Hot Leg Pipe or SG Upper Plenum Connections

Description	Piping Size	ID (in)	Cold Area (ft^2)	Elevation (ft) [Note 1]
Decay Heat Drop Line CR-3 →	12 inch Sch. 140 12 inch Sch. 160	10.500 10.126	0.601 0.559	-1.1 -1.5
Pressurizer Surge Line	10 inch Sch. 140	8.750	0.418	6.0
Flow Meter Connections	1 inch Sch. 160	0.815	0.00362	29.1 "A" 28.8 "B"
Pressure Tap Connections	1 inch Sch. 160	0.815	0.00362	39.2
ANO-1 Pressure Taps for Level Measurement	¾ inch Sch. 160	0.612	0.00204	4 locations [Note 2]
High Point Vent Line	1 inch Sch. 160	0.815	0.00362	48.2
Standard RTE Connection	Temp Probe	1.4	0.0107	39.2
Fast Response RTE Connections	Temp Probe	0.686	0.00257	37.2
OTSG Manway Opening [Note 4]	N/A	16.0	1.396	35.6
OTSG Inspection Opening [Note 3]	N/A	5.0	0.136	36.0

Notes:
1. Elevations are referenced from the reactor vessel outlet (hot leg) centerline. This elevation is 21.25 ft above the upper face of lower SG tube sheet.
2. The elevations of the level taps are not given because their small size limits the tube-to-shell temperature difference consequence.
3. The Oconee replacement OTSGs (ROTSGs) have a 6 inch inspection opening (0.196 ft^2 area) at the same elevation. The TMI-1 and ANO-1 replacement OTSGs (Enhanced OTSGs – EOTSGs) have 5 inch inspection openings
4. The ANO-1 replacement EOTSG has an 18 inch manway opening. The Oconee ROTSG and TMI-1 EOTSG have 16 inch manway openings.

Table A-2 Raised-Loop Plant Hot Leg Pipe or SG Upper Plenum Connections

Description	Piping Size	ID (in)	Cold Area (ft^2)	Elevation (ft) [Note]
Decay Heat Drop Line, DHDL	12 inch Sch. 140	10.500	0.601	-1.1
Pressurizer Surge Line	10 inch Sch. 140	8.750	0.418	27.5
RV Head to HL Vent Line	2.5 inch Sch. 160	2.125	0.0246	62.8
Flow Meter Connections	3/4 inch Sch. 160	0.612	0.00204	55.9 "A" 55.6 "B"
Pressure Tap Connections	3/4 inch Sch. 160	0.612	0.00204	62.0
High Point Vent Line	1 inch Sch. 160	0.815	0.00362	75.0
Standard RTE Connection	Temp Probe	1.4	0.0107	62.0
Fast Response RTE Connections	Temp Probe	0.691	0.00260	64.0
OTSG Manway	N/A	16.0	1.396	62.3
OTSG Inspection Opening	N/A	5.0	0.136	62.8

Note: Elevations are referenced from the reactor vessel outlet (hot leg) centerline. The hot leg centerline is 5.55 ft below the upper face of the SG lower tube sheet.

A.4 Analyzed Tube-to-Shell Temperature Differences

The maximum hypothetical tube-to-shell thermal load results from a postulated full guillotine break of the hot leg near the steam generator entrance. This Regulatory Guide 1.174 submittal requires that the consequences of the large-bore pipe break be considered and evaluated. A bounding generic analysis for this break was completed and it is described in Section A.4.1. This analysis considered all of the B&W-designed plants and selected a composite set of limiting parameters for the LOCA simulation on the 177-FA raised-loop (RL) plant. This plant was selected for this bounding analysis because it has the largest BWST volume, lowest BWST temperature, and refills the secondary side to the lowest level. These three elements tend to make this plant type slightly more limiting, even though it has a higher licensed power level of 2772 MWt.

A.4.1 Limiting Upper Hot Leg Break

Based on the overall evaluations and estimates given in Section A.2, the upper hot leg break was characterized as the LOCA location that would result in the highest tube thermal stresses. A CLPD LBLOCA RELAP5/MOD2 evaluation model (EM) input deck for the raised-loop plant was modified for this analysis by moving the break location to the steam generator inlet nozzle of the loop opposite of the pressurizer. The boundary conditions described in Table A-3 were included with some necessary input changes needed to simulate the entire SG tube thermal analysis transient (including the blowdown, refill, reflood, and long term cooling phase) with RELAP5/MOD2.

The double-ended guillotine break of the hot leg at the steam generator inlet nozzle opened up a 7.18-ft^2 hole from each side (14.4 ft^2 total break area). The break emptied and depressurized the RCS to the containment pressure in roughly 20 seconds as shown in Figure A-7. The ECCS had completed the RV and lower RCS refill below the nozzle belt elevation by 100 seconds. The SG tube refill began shortly thereafter and the tube temperature decrease pushed the broken loop temperature difference to 200 F by 150 seconds as shown in Figure A-5. By 220 seconds, the excess ECCS had refilled the SG tubes to a collapsed level of 15 ft and that refill cooled and depressurized the broken loop secondary side to the RCS pressure. At 220 seconds, the tube average temperature had decreased to near the RCS saturation temperature of 250 F and it was roughly 250 F less than the shell average value. The temperature difference held near that value for the next 200 seconds while the SG tubes completed their refill. After the tubes were refilled, the subcooled ECCS entering the bottom of the tubes began to overwhelm the stored energy on the secondary side and the tube average temperature began to decrease. By 700 seconds the tube inlet temperature had decreased to 40 F. The tube inlet temperature approached the ECCS inlet value because the RVVVs had been artificially forced shut at 228 seconds to circumvent computer code execution problems. The maximum tube-to-shell temperature difference was 374 F at 840 seconds. At the time of the maximum temperature difference, the primary-to-secondary pressure difference at the top of the SG tubes was 30 psi as shown in Figure A-8. The RCS pressure was between 30 and 31 psia and the secondary side pressure was less than 1 psia at that time.

By contrast, the intact loop maximum temperature difference was calculated to be 154 F at 630 seconds as shown in Figure A-6. The intact loop pressure difference was roughly 260 psi at that time, as shown in Figure A-8. The temperature difference was limited because the tubes only refilled to 10 ft. The intact loop manometer has the tube level balanced by the same liquid level in the hot legs. These two levels trap a steam bubble that restricts any additional refill (or increase in the tube-to-shell temperature difference) in the intact loop.

This analysis was completed with several significant conservatisms. The following list gives the conservatisms that were included in the hot leg guillotine break simulation for the thermal-hydraulic tube-to-shell temperature difference calculations.

1. No credit was taken for any main feedwater (MFW) liquid flow into the steam generator due to flashing after the MFW pump trip and coastdown. If the secondary side depressurizes to the saturation pressure (470 psia) of the MFW fluid inlet temperature (460 F), then the MFW in the piping between the isolation valves and the steam generator will start to flash. A rapid depressurization induced by the condensation from the cold ECCS refill of the tubes can result in a significant hot liquid flow into the SG downcomer that could raise the SG level by 6 to 10 feet. Credit for this liquid was not included because of the plant specific variations in the piping volume and the depressurization rate dependencies forcing the MFW liquid insurges. If included, this liquid would slow the rate of SG tube cooldown by adding additional energy to the secondary side and it would also enhance the shell cooling by raising the downcomer pool height. It should be noted that if the fluid in this piping was modeled in detail, the amount of EFW injection would decrease. The additional EFW flow partially offsets this conservatism of omitting the feedwater piping fluid. It is also partially offset by not modeling the feedwater isolation systems from those

plants that have an automatic isolation of a steam generator when its pressure is lower than the other generator.

2. The RVVVs were artificially locked closed when they began to chatter after the initial vessel refill. This modeling choice was made primarily to reduce code numerical difficulties and failures associated with water packing from tiny void collapse. If the RVVVs are continuously open or chattering, then a significant portion of the core decay heat is transported into the downcomer and this energy warms the ECCS fluid that ultimately reaches the inlet of the steam generator tubes. This degree of conservatism from the modeling choice is dependent upon both decay heat rate (time-dependent) and ECCS flow. Generally, the maximum tube-to-shell temperature differences are produced between 700 and 1500 seconds. If the decay heat at this time post reactor shutdown is considered with limiting ECCS flows, the fluid reaching the steam generator tube inlet could be increased by 40 to 70 F above the ECCS injection temperature if all the core decay heat is transported through the RVVVs. This temperature increase would cause a direct reduction in the tube-to-shell temperature difference.

   Break location and relative energy transport mechanisms will determine what portion of the decay heat flows through the RVVVs. For lower hot leg breaks, little decay heat energy is transported through the RVVVs, but this percentage increases significantly when the break is postulated near the top of the hot leg. Breaks between the hot leg U-bend and the steam generator inlet would maximize the decay heat fraction transported through the RVVVs.

3. The outer surface of the steam generator shell is modeled as an adiabatic boundary condition. The heat losses from the shell, especially considering any effect of sprays or RCS leakage running down the steam generator shell can be considerable for the upper hot leg break transients.

4. Other key conservatisms are included in the parameters or boundary conditions used in the analyses. Table A-3 gives some of these key inputs.

Table A-3 Key Boundary Conditions for SG Tube Load Analysis

Parameter	Tube Loads Analysis Value
Decay Heat Multiplier	0.9 times 1971 ANS fission products plus B&W heavy isotopes
BWST Temperature, F	35 F for 177 FA RL; 40 F for 177 FA LL
Maximum BWST Volume, gal	550000 gal for 177 FA RL; 350000 for 177 FA LL
CFT Temperature, F	50 to 70 F (Used 70 F)
ECCS Trip Pressure, psia	1699 psia
ECCS Delay Time, s	0.0 sec
EFW Actuation Setpoint	Reactor Trip
EFW Delay, s	0.0 sec
EFW Temperature, F	40 F
HPI Flow Rates	2 pumps with high best-estimate to runout flows. DB RV head vent LOCA includes 2 Makeup pumps
LPI Flow Rates	2 pumps with high best-estimate to runout flows

A.4.2 Pressurizer Surge Line Breaks

The SG thermal loads resulting from a pressurizer surge line break (0.4239 ft^2) with all the ECCS pumps available have been analyzed for both the raised- and lowered-loop plants. The lowered-loop case used a minimum EFW flow rate of 200 gpm per steam generator because it provided the slowest SG refill and highest SG secondary side pressure that delayed the SG shell cooldown. This smaller break size depressurized the RCS below the secondary side pressure by roughly 120 seconds and reached the CFT fill pressure by 240 seconds as shown in Figure A-15. The CFT and high pumped ECCS flows refilled the RV except for an upper head bubble and initiated SG tube refill by 520 seconds. The hot legs and SG tubes had refilled to the break elevation and core boiling was suppressed by 600 seconds. The tube-to-shell temperature difference, shown in Figures A-13 and A-14, grew rapidly from less than 125 F to 200 F during this rapid SG tube refill period. Adequate core exit subcooling was established between 600 and 700 seconds prompting the operators to throttle the ECCS at 900 seconds (within 5 minutes). The ECCS throttling decreased the RCS pressure, and the resulting saturation temperature decrease caused the SG temperature difference to grow to a maximum of roughly 225 F at roughly 1000 seconds. The maximum pressure difference across the tubes at the time of maximum temperature difference is shown in Figure A-16.

The raised-loop pressurizer surge line break case did not have EFW actuation because the level remained continuously above the level setpoint. This case depressurized below the secondary side pressure by roughly 100 seconds and reached the CFT fill pressure by 190 seconds, as shown in Figure A-11. The CFT and high pumped ECCS flows refilled the cold leg regions and all but the top of the RV by 350 seconds. Core boiling ceased at approximately this time. The hot legs and SG tubes refilled thereafter and reached the break elevation by roughly 600 seconds. The tube-to-shell temperature difference, shown in Figures A-9 and A-10, grew rapidly from less than 25 F to 200 F during this rapid SG tube refill period. Adequate core exit subcooling was established between 400 and 500 seconds, which could prompt the operators to throttle the ECCS within a reasonable time period. Sensitivity studies with and without ECCS throttled showed the most severe results without ECCS throttling at 900 seconds. When the ECCS was throttled, the decrease in the RCS pressure and saturation temperature decrease was less severe than the no throttling case because there was less RCS refill. The SG secondary side depressurized below the primary side and allowed the hot leg trapped steam bubble to be slowly condensed. The hot leg and SG tube levels increased slowly to the top of the SG tubes by 1100 seconds with the ECCS not throttled. This case produced a maximum SG tube-to-shell temperature difference of 235 F at 1240 seconds. The intact loop refill was slower, and as a result it reached a maximum temperature difference of roughly 225 F at

1920 seconds. The maximum pressure difference across the tubes at the time of maximum temperature difference is shown in Figure A-12.

A.4.3 Davis-Besse Continuous Head Vent Line Break

The tube-to-shell temperature difference estimates prepared for this report are discussed in detail in Section A.5. Those estimates revealed that any upper hot leg break size greater than roughly 0.035 ft^2 for the raised-loop plant (roughly 0.07 ft^2 for the lowered-loop plant) should be evaluated as a potentially limiting break for defining limiting tube loads. Reviews of the attached pipe size in Tables A-1 and A-2 show that there is no upper hot leg attached pipe area greater than this size. The steam generator manway and inspection ports are larger in area, although a break from these locations is not considered any more likely than a large-bore RCS pipe break. The only other pipe size that challenges this area is the Davis-Besse 2½ inch schedule 160 continuous RV head vent line that runs from the top of the RV to a special nozzle connected to the 5" SG inspection opening. A double-ended guillotine break of this line near the SG inlet would result in a cumulative break area greater than the size that could be limiting for the raised-loop plant. Therefore, it was determined that this case should be analyzed with the full EM model to determine the maximum temperature differences for a break in the continuous RV head vent pipe at the SG inspection opening nozzle.

A double-ended guillotine break in this line results in a total break area of 0.049 ft^2, although the resistance of the long run of piping from the RV upper head makes its effective size from the RV side appear substantially smaller. The analysis was performed with the plant boundary conditions used for the pressurizer surge line break listed in Table A-3, with the exception of the modeling of the makeup pumps. Makeup pump flow rates were not explicitly included with the pressurizer surge line break, but this break quickly reaches LPI discharge pressures such that excluding flow from the makeup pump is of little consequence. Because the continuous vent line break size is smaller, the RCS pressure will remain above the LPI discharge pressures for a considerable time period. This analysis should include ECCS flow from two HPI pumps plus the two makeup pumps.

A break in the continuous vent line depressurizes the RCS to below 1300 psia during the first 200 seconds, as shown in Figure A-19. The fluid in the hot legs flashed and interrupted natural circulation at about this time. The broken loop liquid level stabilized just below the break location and remained there until 1400 seconds. The intact loop steam generator tubes and hot leg emptied at this time. Shortly thereafter, the RCS pressure reached the CFT fill pressure and the combination of pumped ECCS and CFT flow refilled the broken loop by 2400 seconds. The broken loop flow surge after loop refill rapidly cooled the steam generator tubes and created a maximum tube-to-shell temperature difference of 237 F at this time, as shown in Figure A-17. The primary-to-secondary pressure difference at this time was roughly 425 psid as shown in Figure A-20. At 2800 seconds credit was taken for operator throttling of the ECCS to control core exit subcooling, which had grown from roughly 75 F to near 150 F at 2400 seconds. The reduction in the pumped ECCS inflows limited the maximum broken loop tube-to-shell temperature difference to between 150 and 225 F thereafter. By contrast, the maximum intact loop temperature difference peaked at 90 F at roughly 4400 seconds and remained below this value for the remainder of the transient. Figure A-18 shows these temperature responses, which were also limited by the operator throttling of the ECCS pumps.

The relative break flows from the SG side versus the RV side of the break were used to estimate an effective RCS break area. The discharge rates when both sides of the break were discharging liquid shows that the long run of piping from the RV reduces the break flow to roughly 30 percent of the steam generator side. That makes the effective break area roughly 1.3 times the continuous vent line pipe area or $1.3 * 0.02463 = 0.032\ ft^2$. This effective size was computed for comparison against the estimated temperature differences versus break size in the next section.

A.5 Composite Tube-to-Shell Temperature Difference Estimates

In Section A.2, the thermal-hydraulic evolution that predicts the maximum tube-to-shell temperature differences resulting from postulated LOCAs in various RCS pipe or attached pipe locations was discussed. The results from various LOCA analyses were discussed in Section A.4. These calculations have confirmed the initial evaluations that found the thermal differences from an upper hot leg break to be significantly larger than those of the pressurizer surge line break. These results focus the risk informed scope on the upper hot leg, but it does not rule out other large-bore piping break locations or sizes as less limiting than the pressurizer surge line break. A more detailed evaluation step must be completed to assure that there are no other break locations or sizes that must be considered in the risk informed scope evaluation.

The remaining evaluation uses the described scenarios and completed calculations as a solid foundation, but additional information is needed on the variation with break sizes. This information was obtained from a coarsely noded RELAP5/MOD2 long-term pressure/temperature model to provide estimates of the tube-to-shell temperature difference variations as a function of break size and location. This small, single-loop RELAP5/MOD2 model has been well benchmarked for use in determining reasonable long-term RCS pressure/temperature time histories for other safety evaluations associated with post-LOCA boron precipitation. The ECCS and plant boundary conditions (variables from Table A-3 with maximum ECCS flows and minimum temperatures) were included in generic 177 FA plant LOCA predictions for upper hot leg break sizes of 0.5, 0.1, 0.05, 0.02463 ft^2. These calculations were used to give the tube average temperatures along with SG shell temperatures in the liquid pool and steam regions that could be used to estimate maximum tube-to-shell differences for different hot leg LOCAs.

The approach used to estimate the temperature differences was to include the three time-dependent temperatures (tube average, shell liquid region, and shell steam region data) for each break size into a spreadsheet. The spreadsheet was used to calculate the time-dependent tube-to-shell temperature difference from these parameters by using plant-specific averaging techniques for the shell temperatures and applying limits to the minimum tube temperatures to simulate different break locations.

This approach recognized that the SG downcomer pool height and its liquid temperature control the shell average temperature. The shell average temperature was calculated based on a length-weighted pool height fraction times the liquid shell temperature plus the steam height fraction times the steam shell temperature. The SG downcomer pool height is a plant-type specific parameter that was varied to account for the different loss of adequate subcooling margin levels of 10 and roughly 28 ft for the raised- versus the lowered-loop plants, respectively. The pool height for these calculations is also break-size and location-dependent. It is representative of a collapsed level for small breaks and a mixture level for larger breaks. The larger breaks that result in significant SG secondary depressurization from tube refill with ECCS can result in flashing and boiling from the wall heat that can cause the level to swell above the collapsed level.

The spreadsheet used the tube average data from an upper hot leg break to simulate all break locations. It defined minimum tube temperature limits to simulate other break locations, such as RCS saturation temperature for middle hot leg breaks or the ECCS inlet temperature plus the core decay heat enthalpy rise for the upper hot leg breaks. The tube inlet temperature limits also included the effect of operator throttling of the ECCS pumps to control core exit subcooling and consideration of when the ECCS inlet temperature increases due to suction transfer from the BWST to the sump.

The techniques discussed were incorporated into the spreadsheet and benchmarked against the full EM analyses of the two pressurizer surge line break cases and the full area upper hot leg guillotine break case. The spreadsheet method estimated the maximum tube-to-shell temperature differences within several degrees, as shown in Table A-4. The time-dependent predictions were reasonable, but it varied such that the times of the peak temperature difference were shifted slightly.

Table A-4 Maximum Thermal Difference Benchmark Comparisons

Break	Full EM Analysis		Spread Sheet Estimation	
	Maximum $\Delta T_{tube-to-shell}$ (F)	Time of Maximum (sec)	Maximum $\Delta T_{tube-to-shell}$ (F)	Time of Maximum (sec)
RL Pzr Surge Line	235	1240	235	1000
LL Pzr Surge Line	225	1110	225	1000
RL 2A-G of upper HL	374	748	375	840

These excellent benchmark comparisons provide some assurance that the estimates produced by this spreadsheet method are reasonable for evaluating the maximum tube-to-shell temperatures for upper hot leg breaks with SG tube liquid throughput and for hot leg riser breaks without SG tube liquid throughput. Table A-5 gives the lowered-loop inputs (SG levels and ECCS flows) and predictions for the broken loop with upper hot leg break sizes of 14.1, 0.5, 0.1, 0.05, and 0.02463 ft^2 in cases LL-1 though LL-5, respectively. The middle hot leg breaks for the same break sizes are given by cases LL-6 through LL-10 for the broken loop. The maximum intact loop temperature difference for the upper hot leg break was reported as the same value for the broken loop of a middle HL break. The intact loop of the middle HL break was expected to be slightly better than the broken loop, because the intact loop trapped steam bubble restricted the steam throughput. The maximum intact loop temperature was reported as the broken loop temperature minus 10 F. (For the smaller break sizes, whenever a temperature difference of less than 130 F was predicted, a range between the lower predicted value and 130 F was given. These lower temperatures really extend the methods used in this estimation, and it is believed that these low temperatures may be too favorable. That is, it is likely that the tube-to-shell temperature difference with some tube refill would be closer to 130 F than the lower prediction.)

Figure A-21 gives the estimated maximum tube-to-shell-temperature differences as a function of break size and location for the lowered-loop calculations and extrapolations. Figure A-21 also shows the analyzed pressurizer surge line break tube-to-shell temperature difference. The CLPS, CLPD, and lower hot leg breaks were not explicitly calculated, but have been characterized to the extent possible with readily available thermal-hydraulic information. The lower hot leg breaks have been shown with uncertainty bars, because these breaks are more difficult to categorize. A lower hot leg break near the pressurizer surge line will be slightly better than the middle hot leg break, while a break at the reactor vessel exit nozzle will be closer to the CLPD break.

Table A-6 gives the raised-loop inputs (SG levels and ECCS flows) and predictions for upper hot leg break sizes of 14.1, 0.5, 0.1, 0.05, and 0.02463 ft^2 in cases RL-1 though RL-5, respectively. The middle hot leg breaks for the same break sizes are given by cases RL-6 through RL-10. The largest upper hot leg break produced a tube-to-shell temperature difference of 375 F. Figure A-22 gives the estimated maximum tube-to-shell-temperature differences as a function of break size and location. Figure A-22 also shows the analyzed double-ended hot leg U-bend guillotine break, pressurizer surge line break, and continuous hot leg vent line break tube-to-shell temperature differences. The CLPS, CLPD, and lower hot leg breaks were not explicitly calculated, but have been characterized to the extent possible with any available thermal-hydraulic information. Again, lower hot leg breaks have been shown with uncertainty bars. A lower hot leg break near the pressurizer surge line will be slightly better than the middle hot leg break, while a break at the reactor vessel exit nozzle will be closer to the CLPD break.

The upper hot leg break predictions for the raised-loop plant showed that any break size greater than 0.035 ft^2 remained above the pressurizer surge line break analyzed with the full EM case. This prediction suggests that a double-ended guillotine break of the Davis Besse RV continuous vent line connected between the top of the RV and the SG inlet plenum should be analyzed with full EM model to confirm the estimates. This case was analyzed, and the results were discussed in Section A.4.3. The maximum tube-to-shell temperature difference was calculated to be 237 F at 2425 seconds.

Table A-5 Lowered-Loop Plant Tube-to-Shell Temperature Approximations

Lowered-Loop Plant Case	Break Size & Location	Maximum Broken Loop $\Delta T_{t\text{-}t\text{-}s}$ (F)	Maximum Intact Loop $\Delta T_{t\text{-}t\text{-}s}$ (F)	Approx. Time of Highest Max $\Delta T_{t\text{-}t\text{-}s}$ (sec)
LL-1	14.1 ft^2 Upper Hot Leg	350	245	708
LL-2	0.5 ft^2 Upper Hot Leg	290	225	1760
LL-3	0.1 ft^2 Upper Hot Leg	247	158	3260
LL-4	0.05 ft^2 Upper Hot Leg	199	130	5540
LL-5	0.025 ft^2 Upper Hot Leg	185	119 to 130	5880
LL-6	14.1 ft^2 Middle Hot Leg	245	235	708
LL-7	0.5 ft^2 Middle Hot Leg	225	215	1000
LL-8	0.1 ft^2 Middle Hot Leg	158	148	1910
LL-9	0.05 ft^2 Middle Hot Leg	130	120 to 130	3160
LL-10	0.025 ft^2 Middle Hot Leg	119 to 130	109 to 130	3760
LL-6A (Note 1)	14.1 ft^2 Lower Hot Leg	140 to 233	140 to 233	708
LL-7A (Note 1)	0.5 ft^2 Lower Hot Leg	128 to 213	128 to 213	1000
LL-8A (Note 1)	<0.1 ft^2 Lower Hot Leg	98 to 163	98 to 163	1910
LL-6B (Note 2)	8.6 ft^2 CLPS	205	215	708
LL-7B (Note 2)	0.5 ft^2 CLPS	185	195	1000
LL-8B (Note 2)	0.1 ft^2 CLPS	118 to 130	128 to 130	1910
LL-9B (Note 2)	0.05 ft^2 CLPS	90 to 130	100 to 130	3160
LL-10B (Note 2)	0.025 ft^2 CLPS	79 to 130	89 to 130	3760
LL-11 Estimate	>0.5 ft^2 CLPD	<100	<100	
LL-12 Estimate	0.05 to 0.1 ft^2 CLPD	100 to 150	100 to 150	
LL-13 Estimate	< 0.05 ft^2 CLPD	Operator	Action Dep.	

Notes:

1. These temperature differences are strongly dependent on the lower hot leg break elevation. The nominal value is estimated as 80% of the numbered case broken loop value given minus 10 F [i.e. $(0.8*\Delta T_{BL\ case}) - 10$] with a 25% uncertainty band.

2. These temperature differences were reductions (30 F for intact loop, 40 F for broken loop) in the difference given for the broken loop value in the numbered case listed.

Table A-6 Raised-Loop Plant Tube-to-Shell Temperature Approximations

Lowered-Loop Plant Case	Break Size & Location	Maximum Broken Loop ΔT_{t-t-s} (F)	Maximum Intact Loop ΔT_{t-t-s} (F)	Approx. Time of Highest Max ΔT_{t-t-s} (sec)
RL-1	14.1 ft^2 Upper Hot Leg	375	270	748
RL-2	0.5 ft^2 Upper Hot Leg	325	235	2530
RL-3	0.1 ft^2 Upper Hot Leg	288	180	3260
RL-4	0.05 ft^2 Upper Hot Leg	246	154	5540
RL-5	0.025 ft^2 Upper Hot Leg	223	138	5880
RL-6	14.1 ft^2 Middle Hot Leg	270	260	708
RL-7	0.5 ft^2 Middle Hot Leg	235	225	1000
RL-8	0.1 ft^2 Middle Hot Leg	180	170	1980
RL-9	0.05 ft^2 Middle Hot Leg	154	144	3160
RL-10	0.025 ft^2 Middle Hot Leg	138	130	3760
RL-6A (Note 1)	14.1 ft^2 Lower Hot Leg	155 to 258	155 to 258	708
RL-7A (Note 1)	0.5 ft^2 Lower Hot Leg	134 to 223	134 to 223	1000
RL-8A (Note 1)	<0.1 ft^2 Lower Hot Leg	101 to 168	101 to 168	1980
RL-11 Estimate	>0.5 ft^2 Upper CLPS	<100	<100	
RL-12 Estimate	<0.1 ft^2 Upper CLPS	100 to 150	100 to 150	
RL-13 Estimate	>0.5 ft^2 CLPD	<100	<100	
RL-14 Estimate	<0.1 ft^2 CLPD	100 to 150	100 to 150	

Note 1: These temperature differences are strongly dependent on the lower hot leg break elevation. The nominal value is estimated as 80% of the numbered case given minus 10 F with a 25% uncertainty band.

A.6 Thermal-Hydraulic Summary and Conclusions

In this appendix, material is presented to define the worst break locations and sizes as they relate to the generation of high tube thermal stresses following LOCA. These limiting tube thermal consequences clearly focus the scope of the PRA calculations for the risk-informed submittal on the large-bore upper hot leg pipe, because these breaks can generate higher SG tube thermal loads than the analyzed RCS attached pipe break (i.e., pressurizer surge line or Davis-Besse continuous upper head vent). The large-bore pipe evaluations for both the lowered-loop and the raised-loop plant concluded that only the upper hot leg breaks could produce higher tube loads than the pressurizer surge line break. However, it was discovered through the evaluation process, and confirmed though a detailed thermal hydraulic analysis, that a break in the Davis-Besse continuous head vent line is similar to but slightly more limiting than the pressurizer surge line break.

A.7 References

[A-1] B&W Topical Report BAW-1847, Rev 1, "Leak-Before-Break Evaluation of Margin Against Full Break for RCS Primary Piping of B&W Design NSS," September 1985.

[A-2] NRC Safety Evaluation of B&W Owners Group Reports Dealing with Elimination of Postulated Pipe Breaks in PWR Primary Main Loops, dated December 12, 1985.

[A-3] FTI Topical Report BAW-2243A, "The B&W Owners Group Generic License Renewal Program, Demonstration of the Management of Aging Effects for the Reactor Coolant System Piping," June 1996.

Figure A-1 177-FA Lowered-Loop RCS Conditions Following a CLPD Break

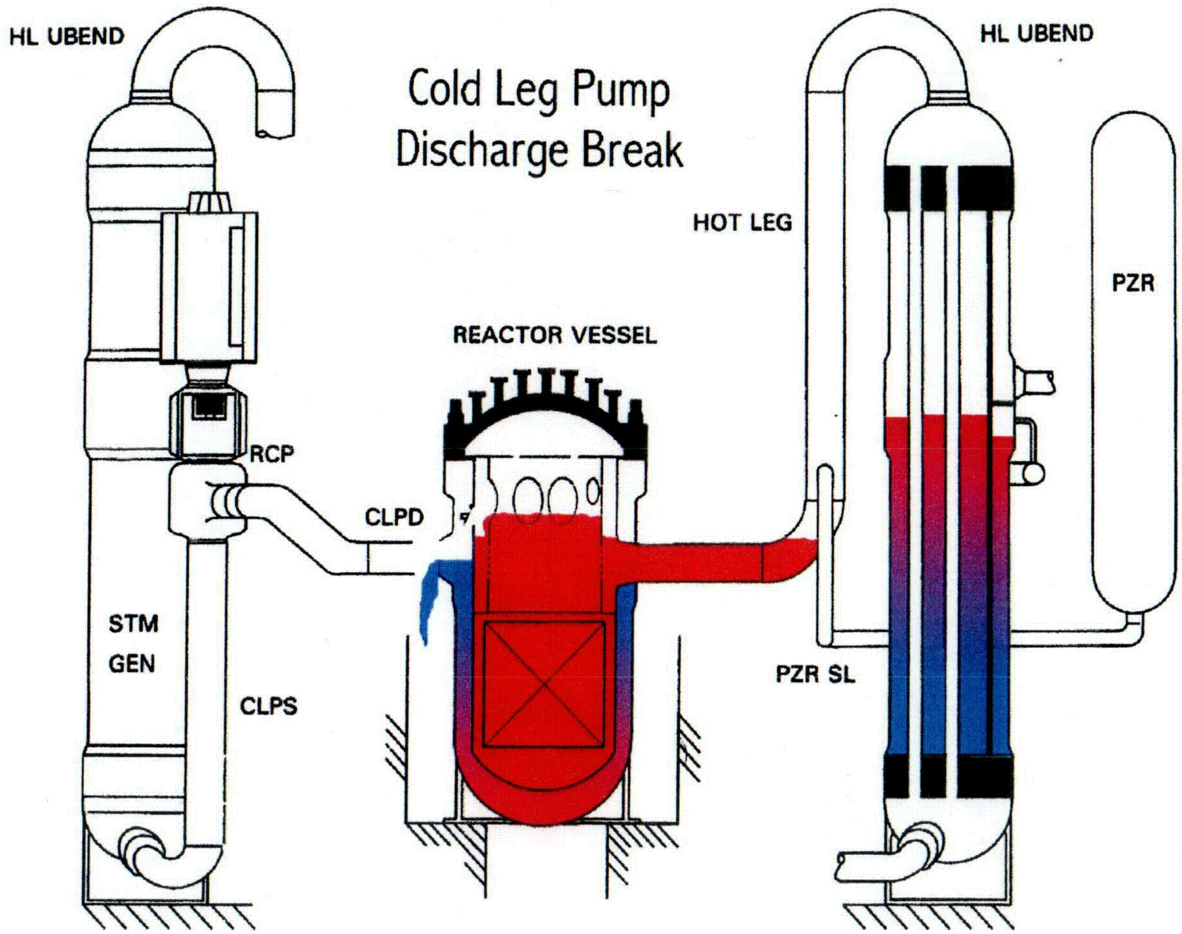


Figure A-2 177-FA Lowered-Loop RCS Conditions Following a Pressurizer Surge Line Break

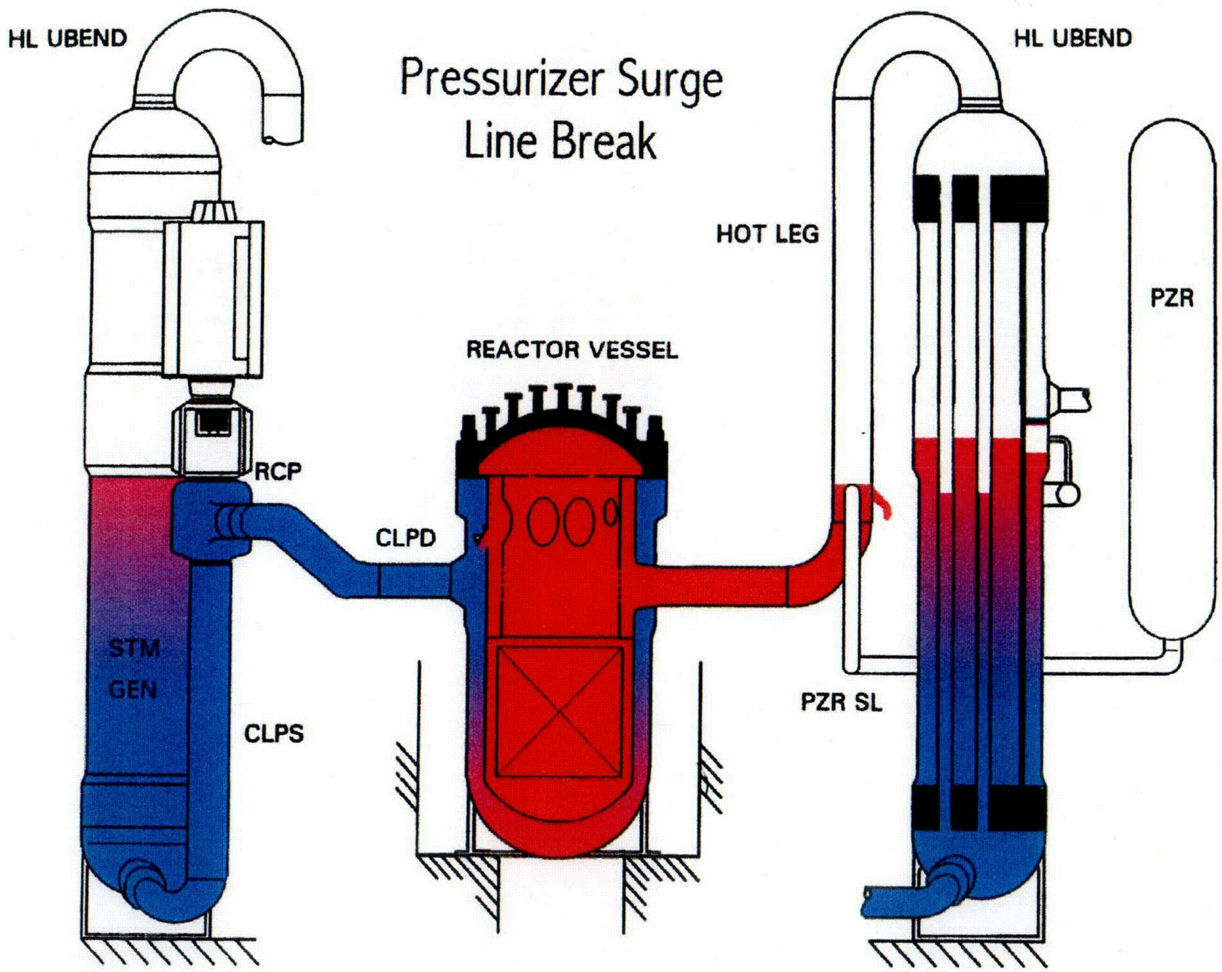


Figure A-3 177-FA Lowered-Loop RCS Conditions Following a Hot Leg U-Bend Break

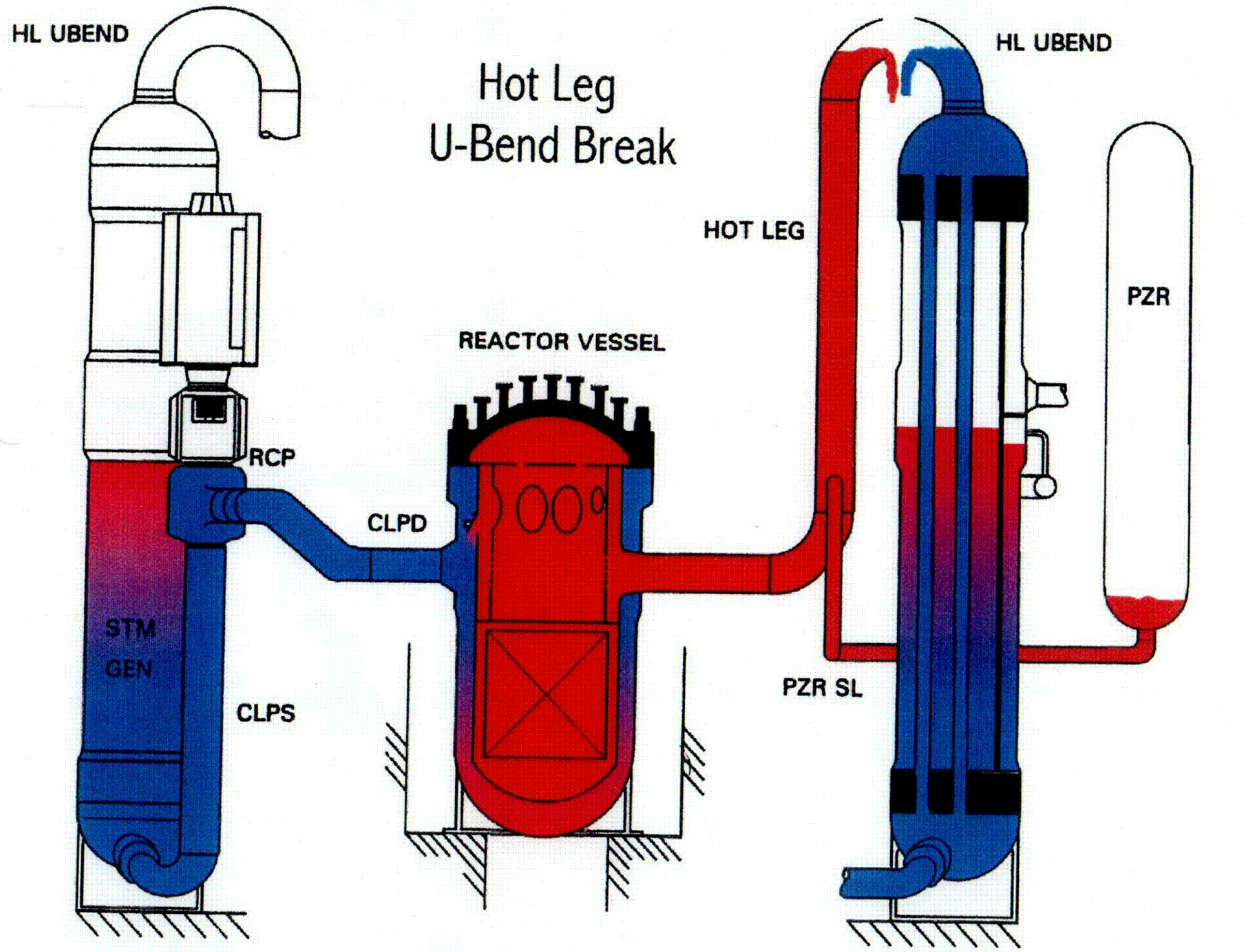


Figure A-4 177-FA Raised-Loop RCS Conditions Following a

Pressurizer Surge Line Break

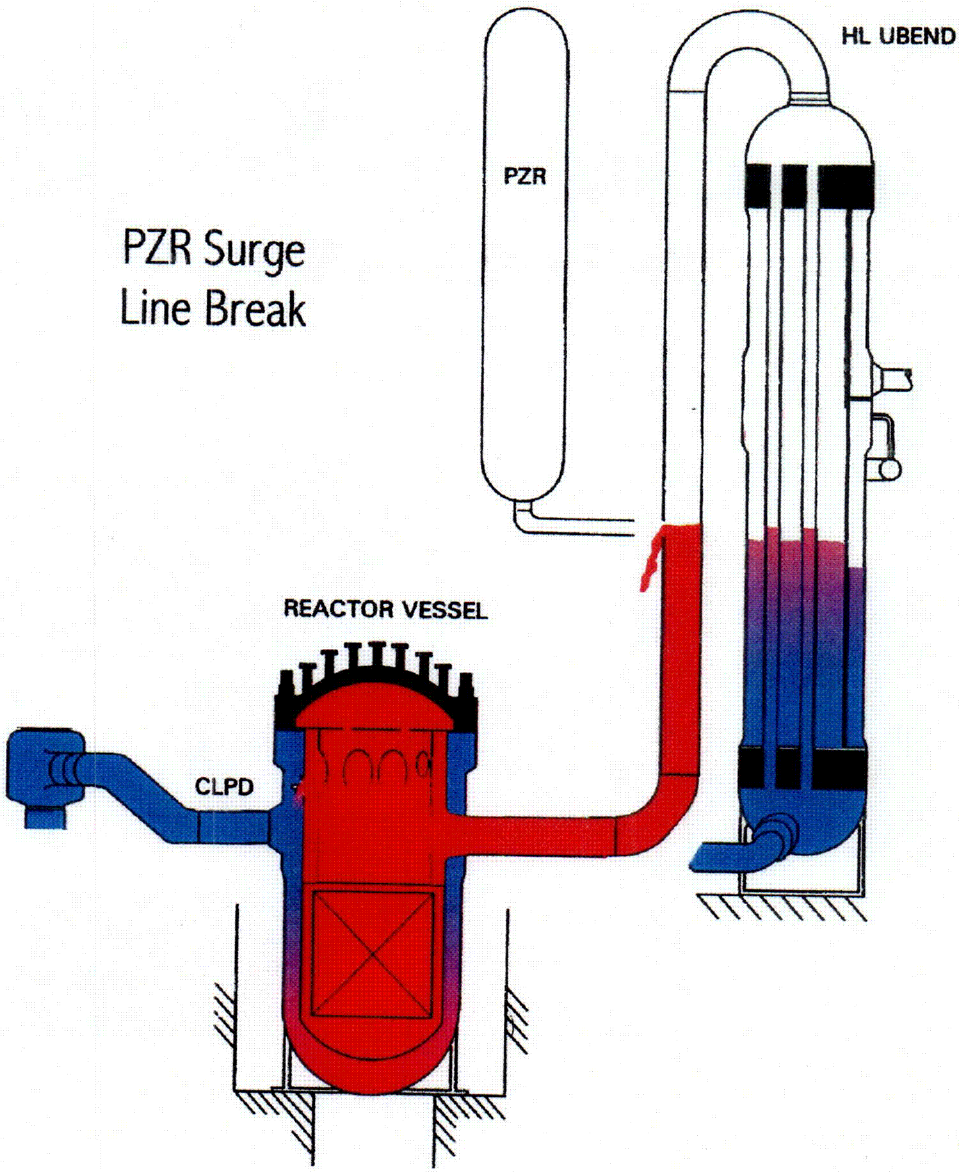


FIGURE A-5. 177-FA Raised-Loop 14.4 Sq ft DE Hot Leg Break
Broken Loop Shell and Tube Temperatures

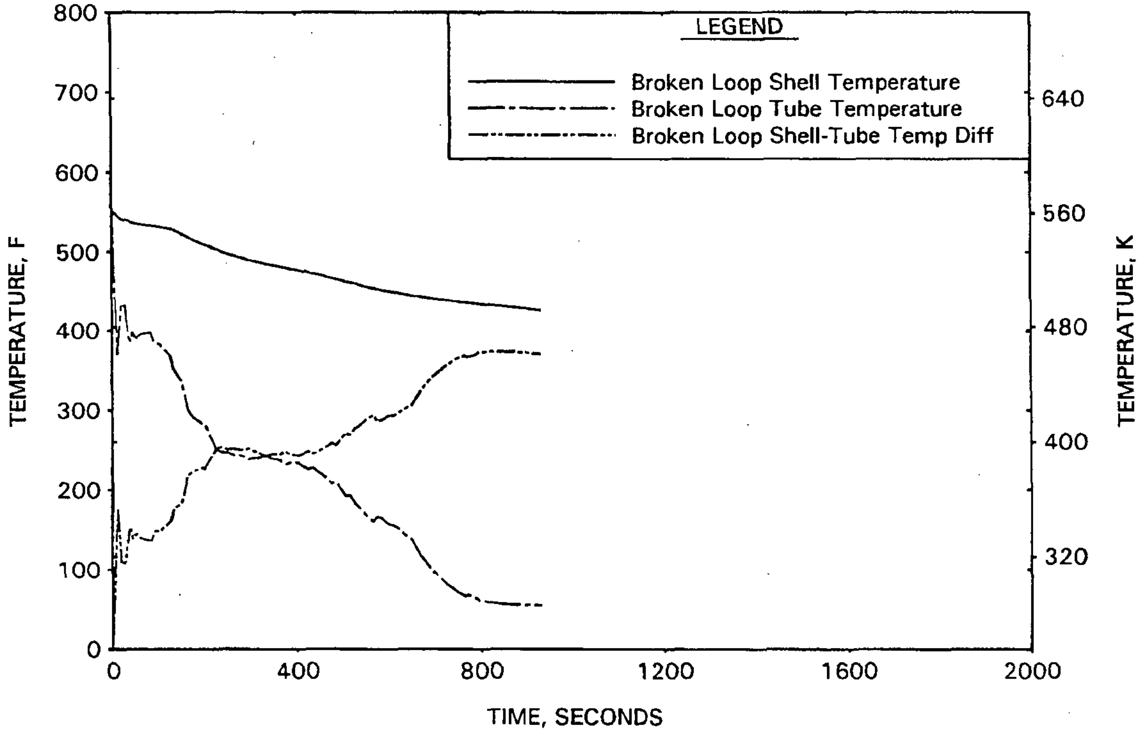


FIGURE A-6. 177-FA Raised-Loop 14.4 Sq ft DE Hot Leg Break
Intact Loop Shell and Tube Temperatures

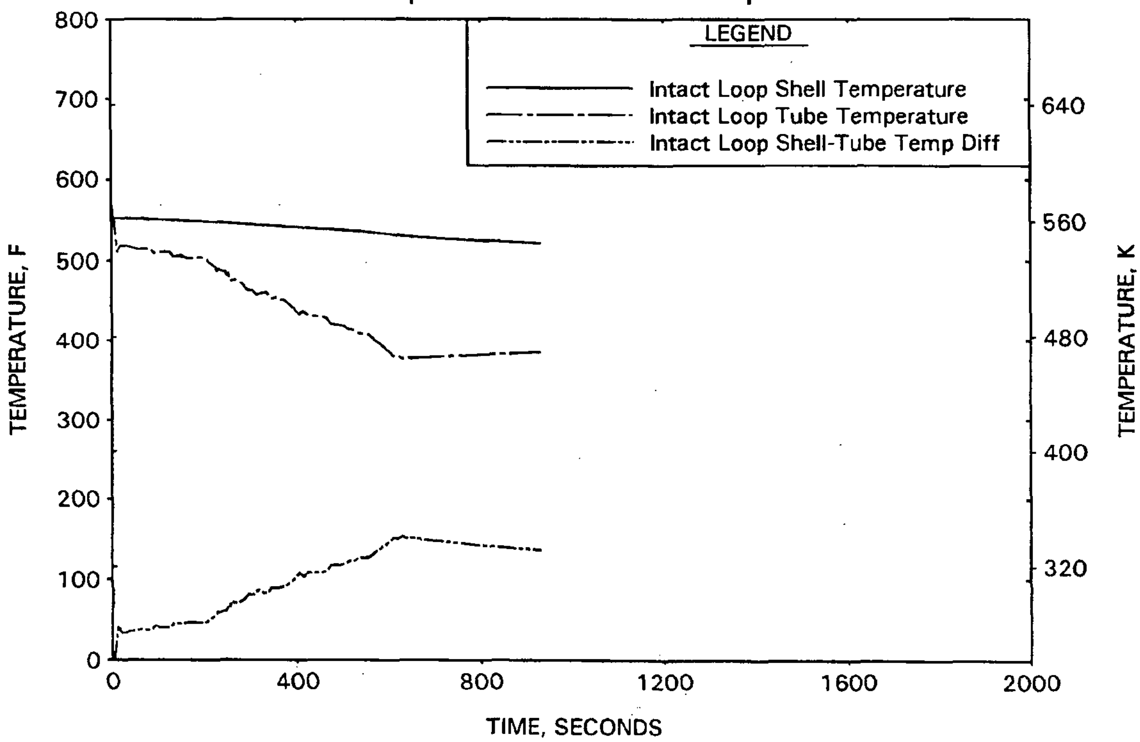


FIGURE A-7. 177-FA Raised-Loop 14.4 Sq ft DE Hot Leg Break
Primary and Secondary Pressures

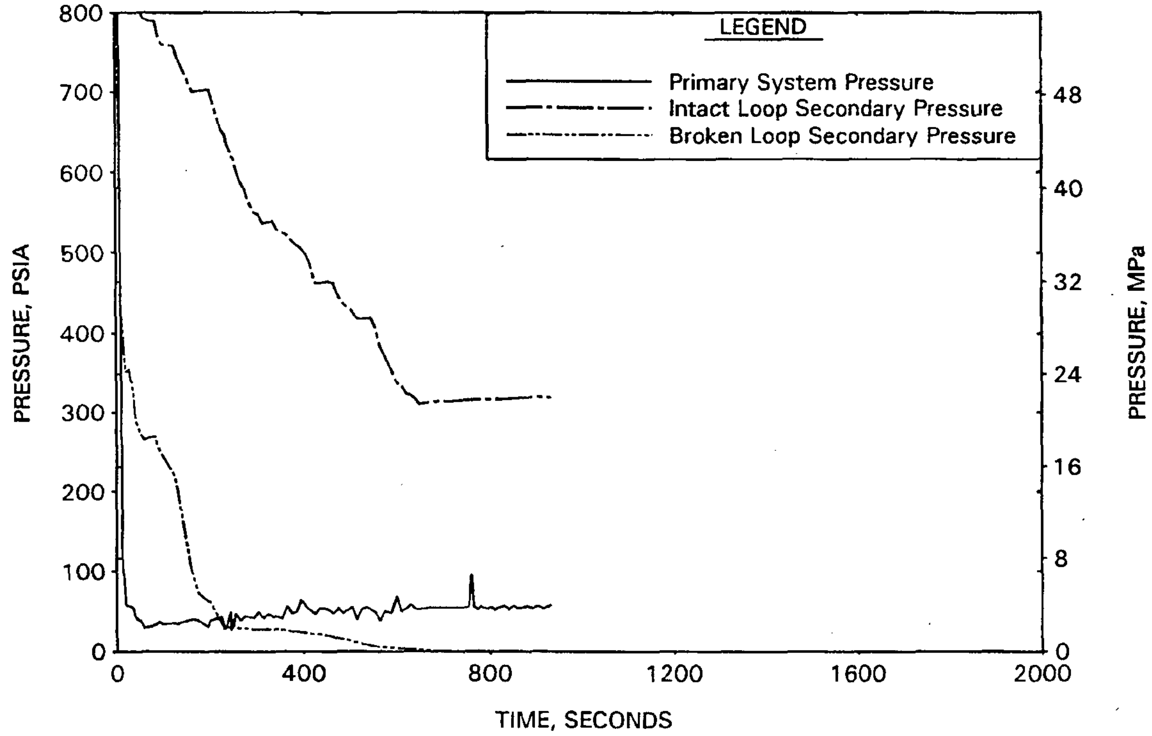


FIGURE A-8. 177-FA Raised-Loop 14.4 Sq ft DE Hot Leg Break
Tube to Shell Temperature & Pressure Differences

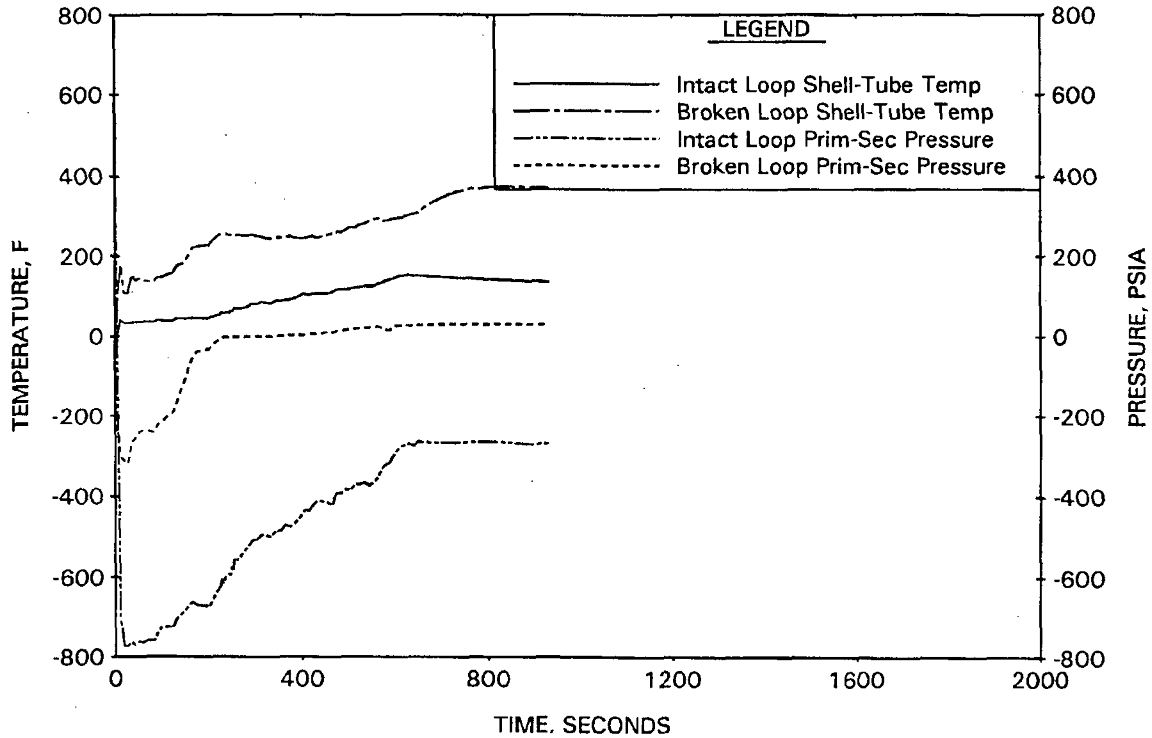


FIGURE A-9. 177-FA Raised-Loop 0.42 Sq ft PZR Surge Line Break
Broken Loop Shell and Tube Temperatures

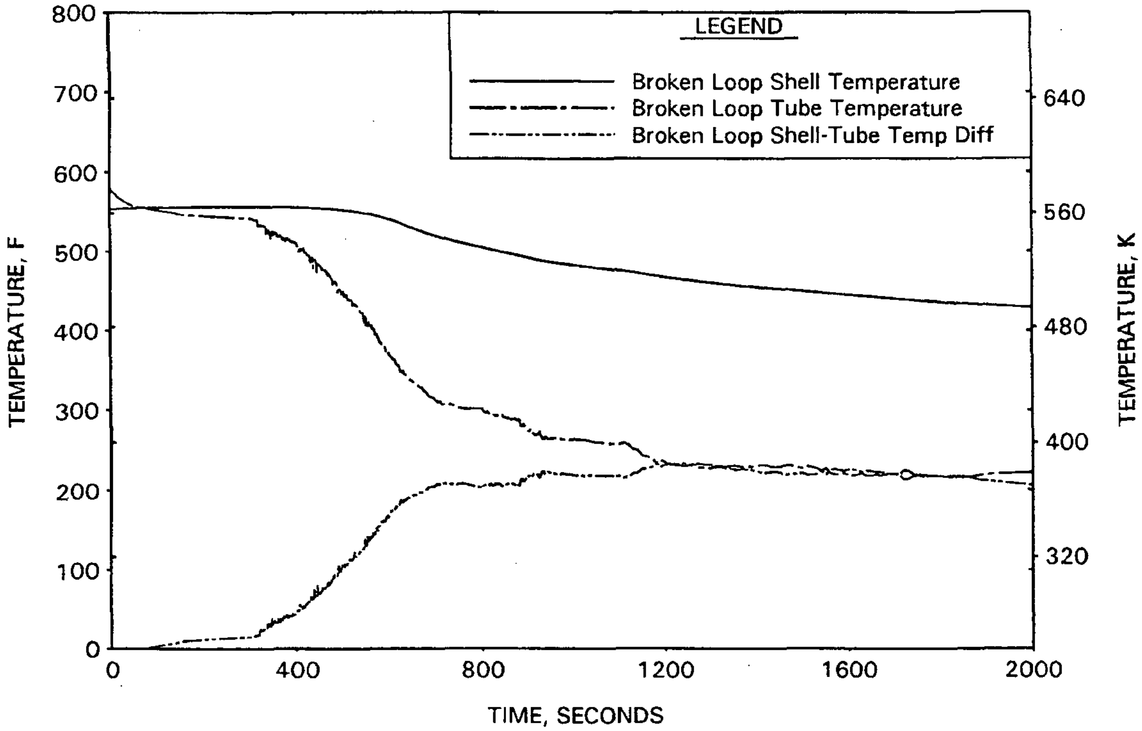


FIGURE A-10. 177-FA Raised-Loop 0.42 Sq ft PZR Surge Line Break
Intact Loop Shell and Tube Temperatures

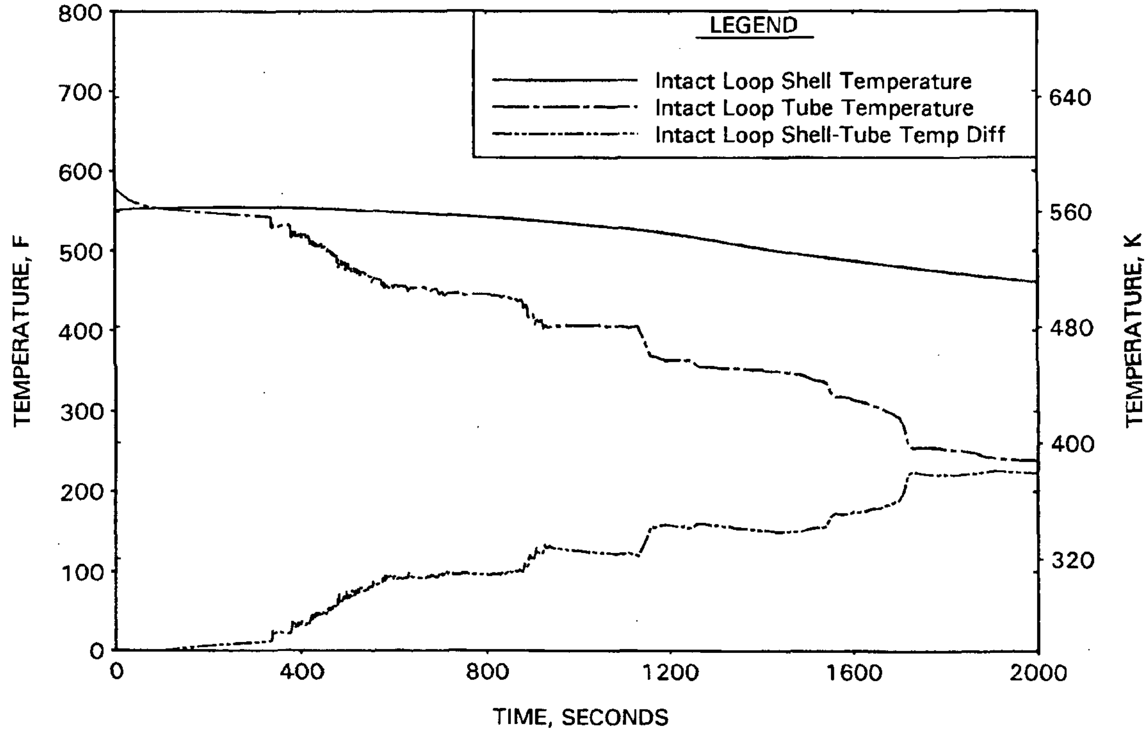


FIGURE A-11. 177-FA Raised-Loop 0.42 Sq ft PZR Surge Line Break
Primary and Secondary Pressures

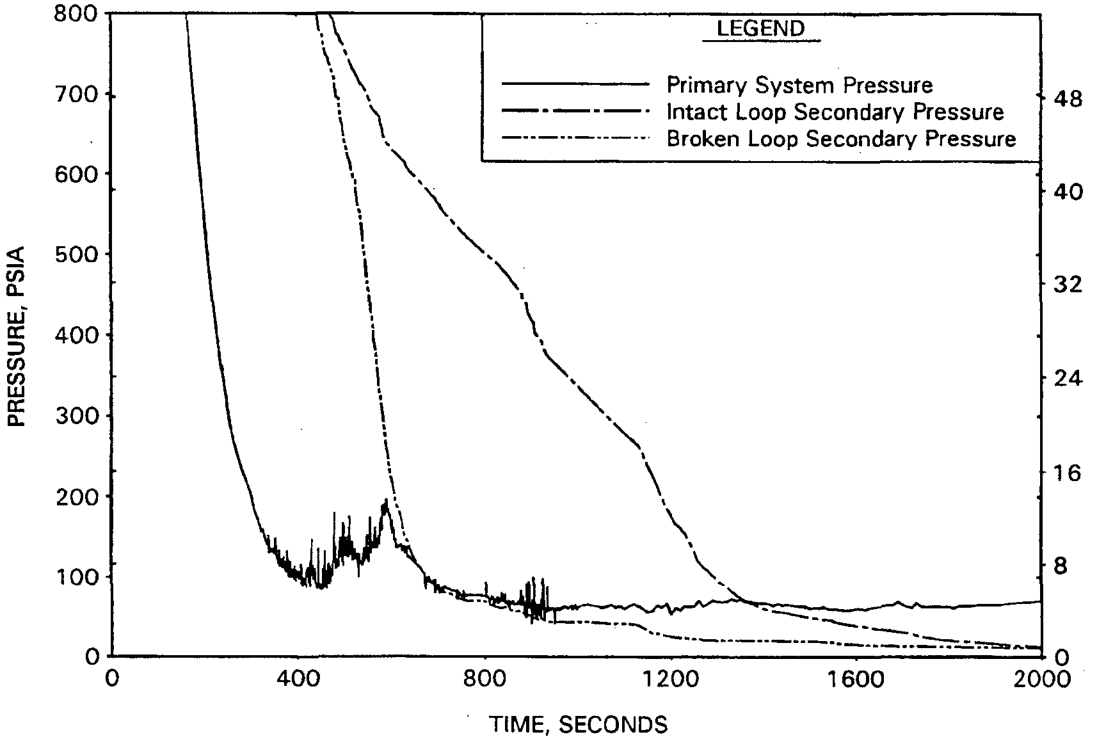


FIGURE A-12. 177-FA Raised-Loop 0.42 Sq ft PZR Surge Line Break
Tube to Shell Temperature & Pressure Differences

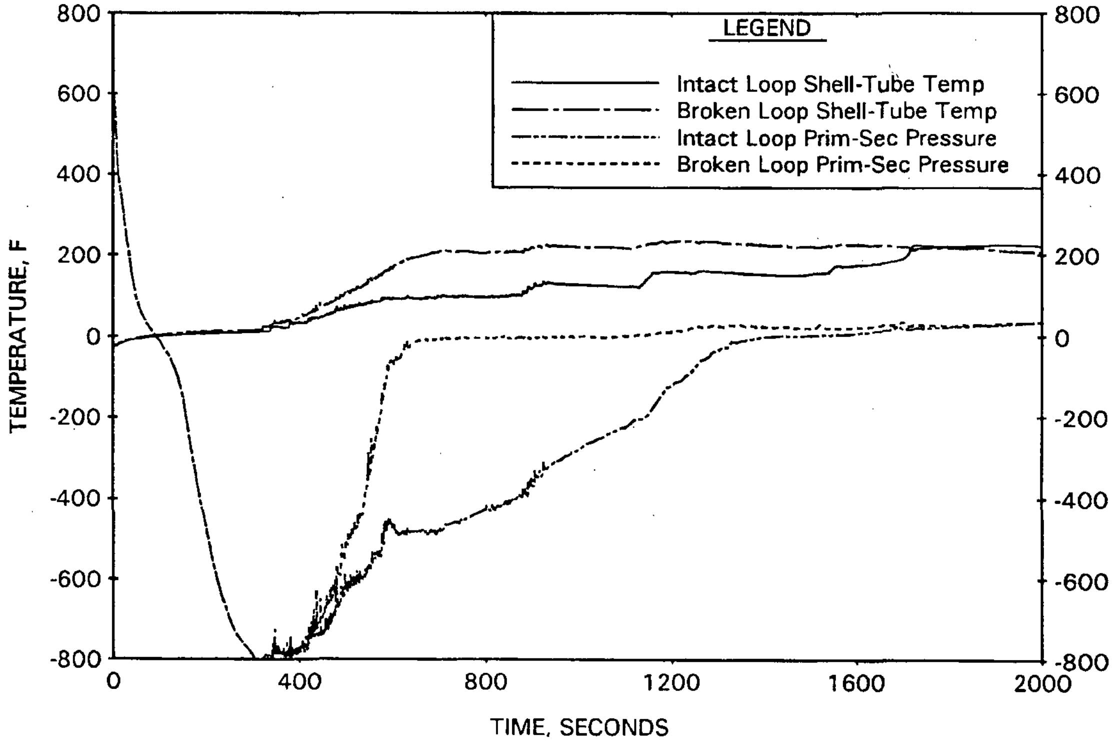


FIGURE A-13. 177-FA Lowered-Loop 0.42 Sq ft PZR Surge Line Break
Broken Loop Shell and Tube Temperatures

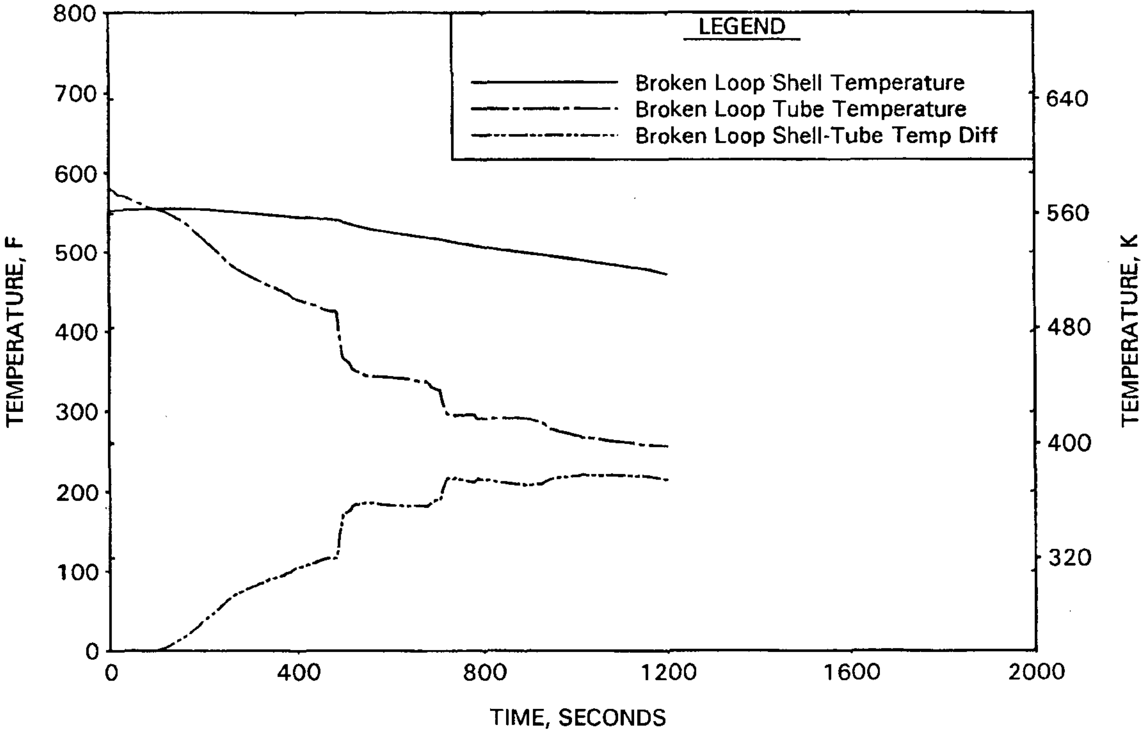


FIGURE A-14. 177-FA Lowered-Loop 0.42 Sq ft PZR Surge Line Break
Intact Loop Shell and Tube Temperatures

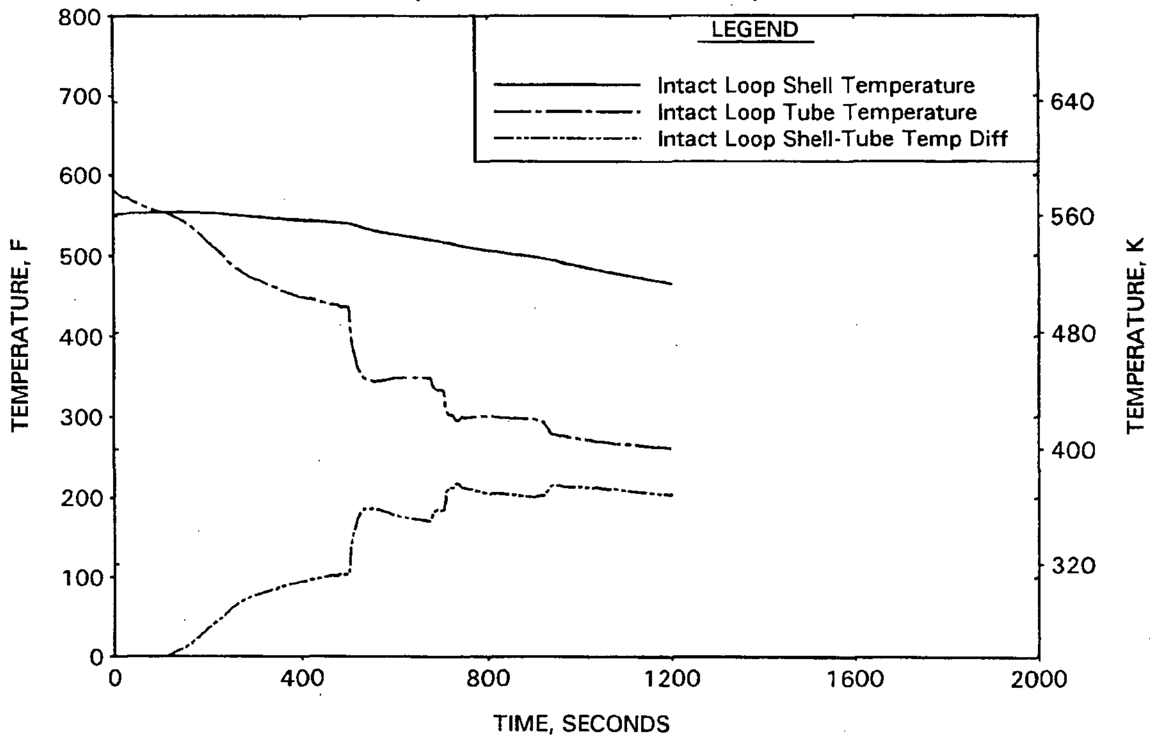


FIGURE A-15. 177-FA Lowered-Loop 0.42 Sq ft PZR Surge Line Break
Primary and Secondary Pressures

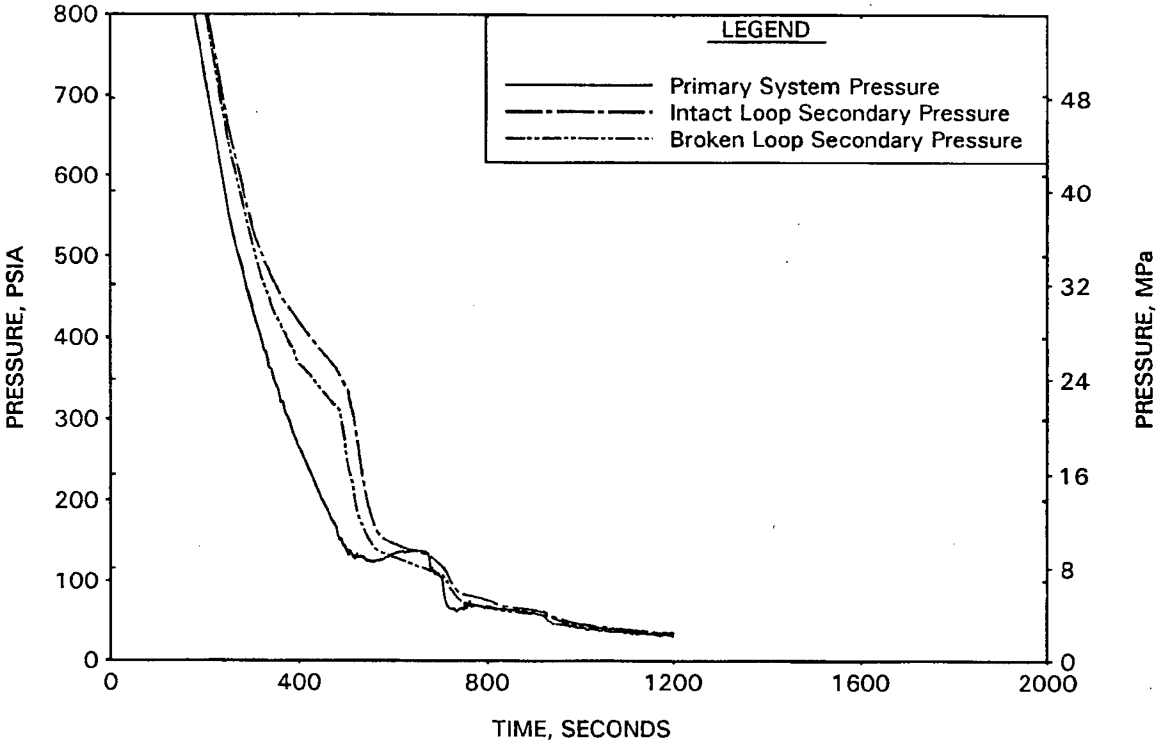


FIGURE A-16. 177-FA Lowered-Loop 0.42 Sq ft PZR Surge Line Break
Tube to Shell Temperature & Pressure Differences

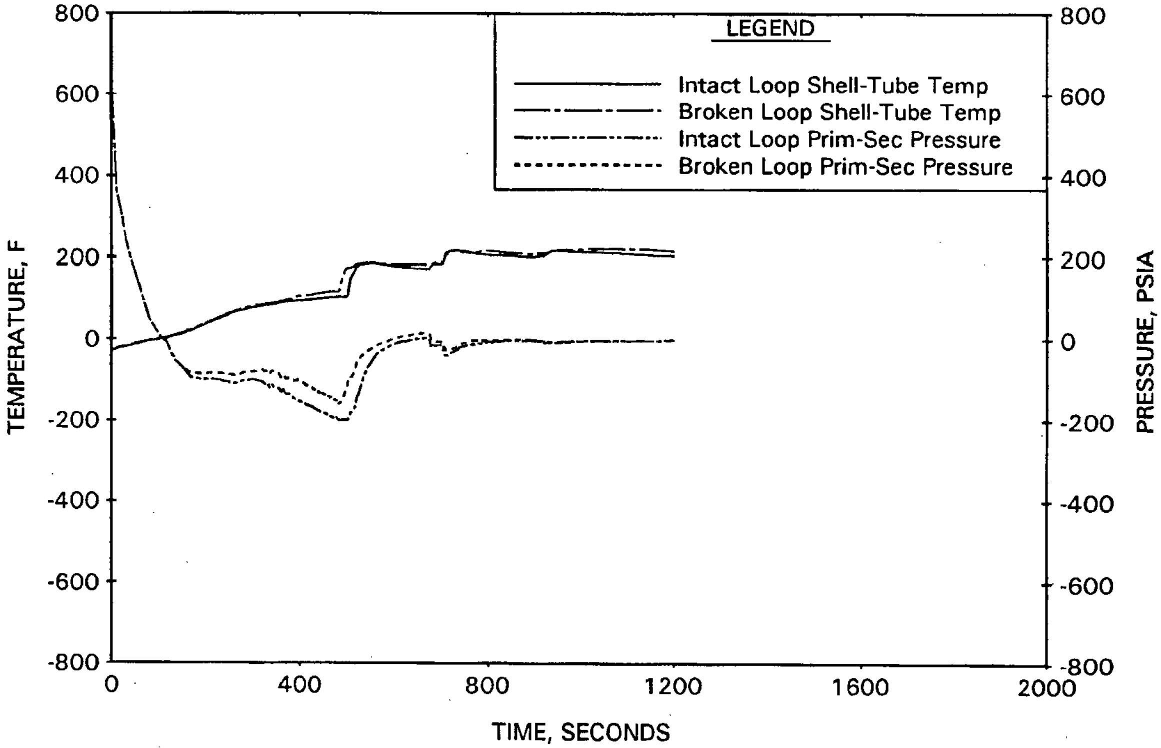


FIGURE A-17. 177-FA Raised-Loop 0.049 Sq ft Upper Head Vent Break Broken Loop Shell and Tube Temperatures

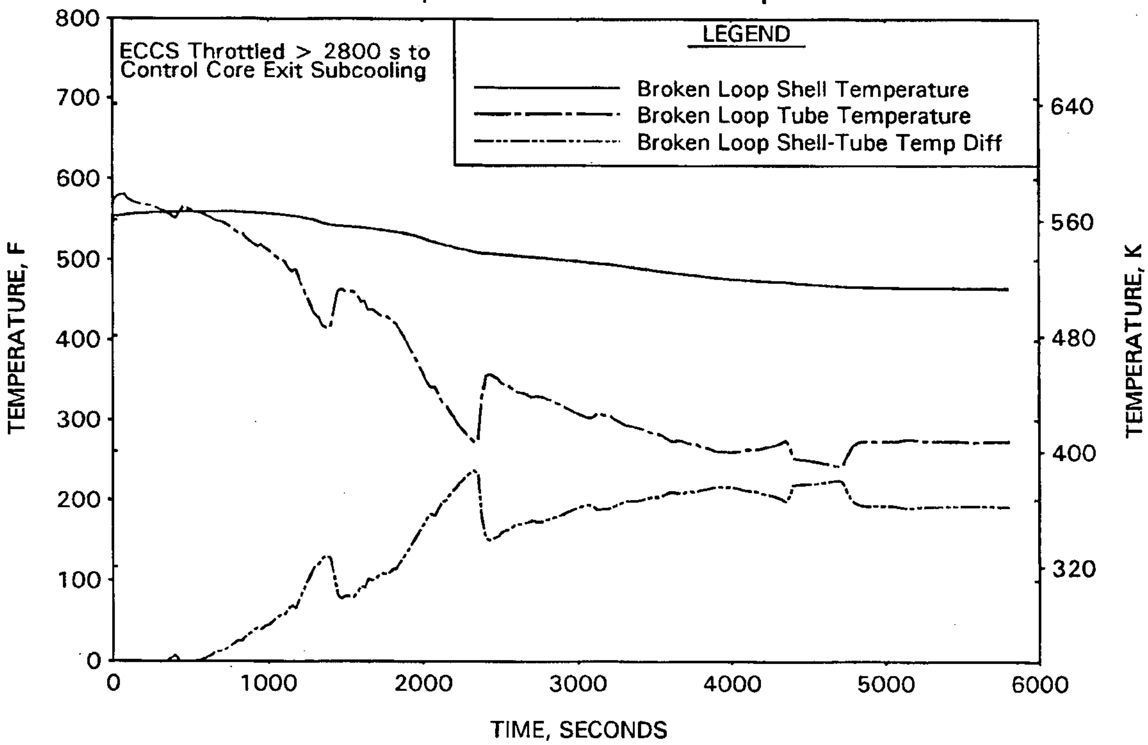


FIGURE A-18. 177-FA Raised-Loop 0.049 Sq ft Upper Head Vent Break Intact Loop Shell and Tube Temperatures

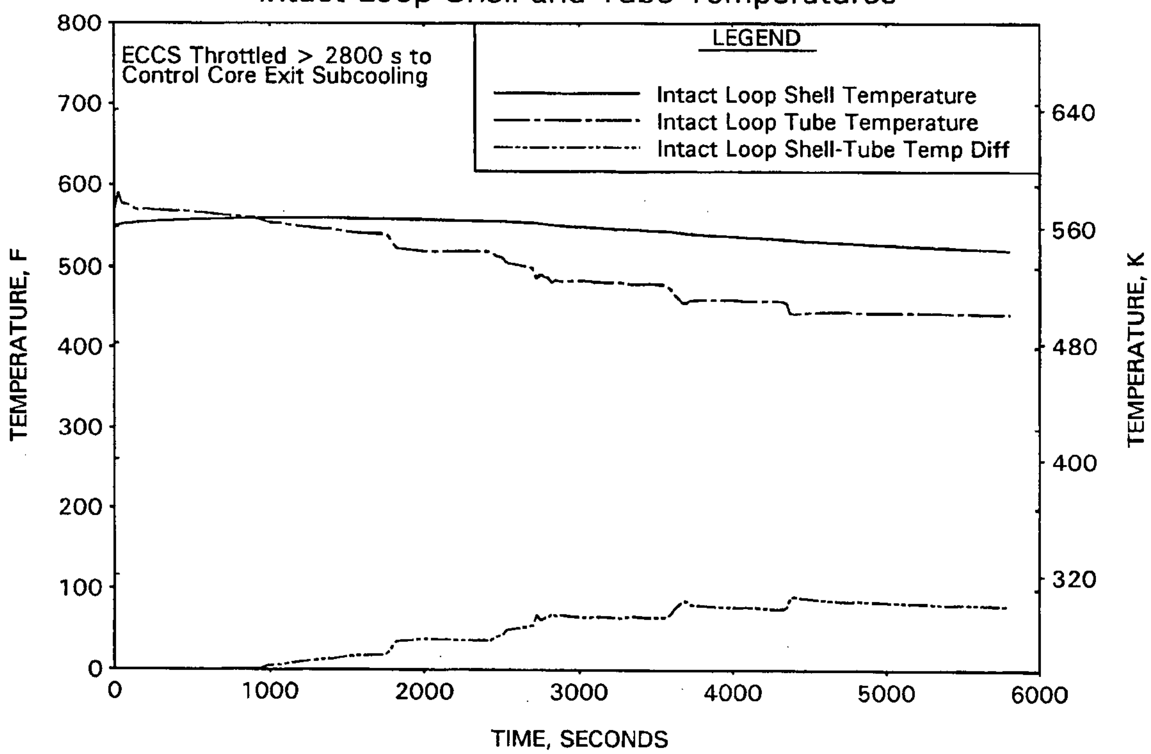


FIGURE A-19. 177-FA Raised-Loop 0.049 Sq ft Upper Head Vent Break Primary and Secondary Pressures

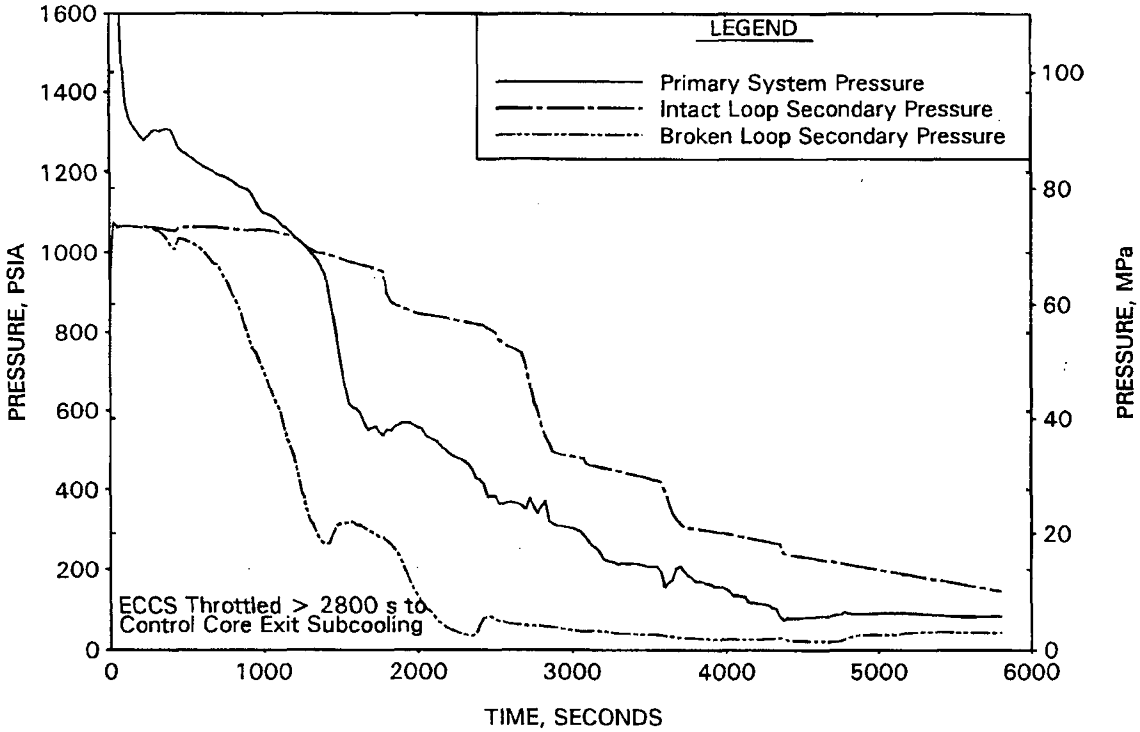


FIGURE A-20. 177-FA Raised-Loop 0.049 Sq ft Upper Head Vent Break Tube to Shell Temperature & Pressure Differences

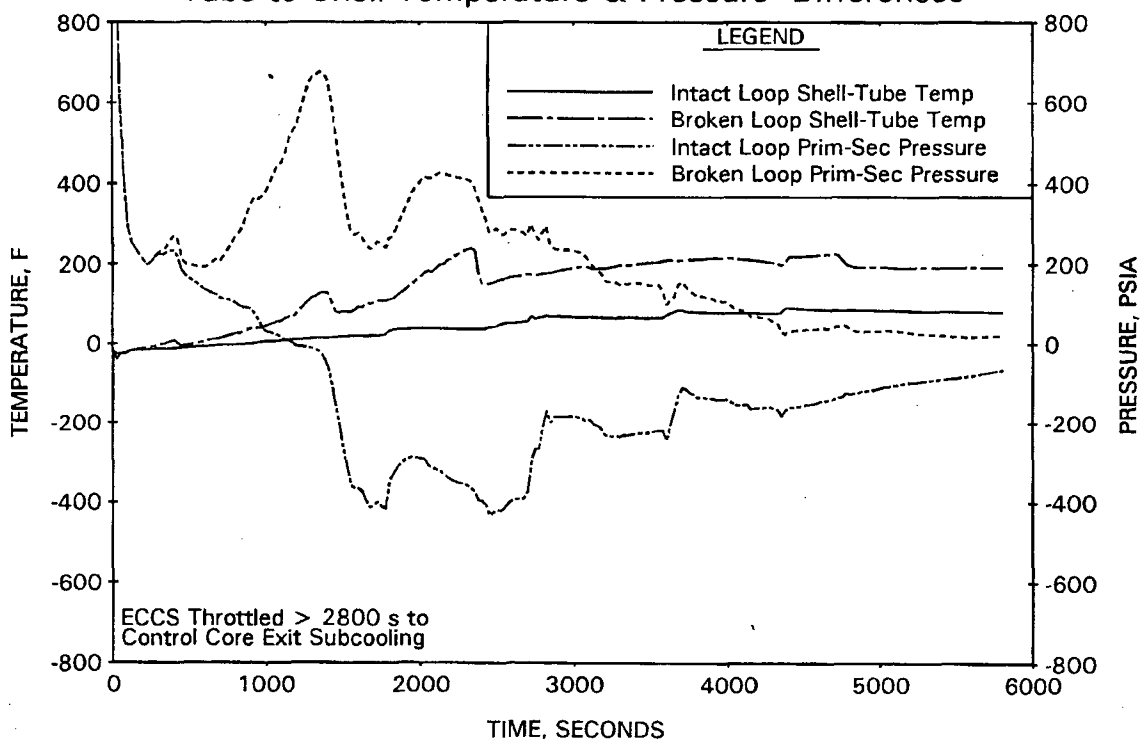


Figure A-21 177-FA Lowered-Loop Plant Estimated Maximum Tube-to-Shell Temperature Differences versus Break Size and Location.

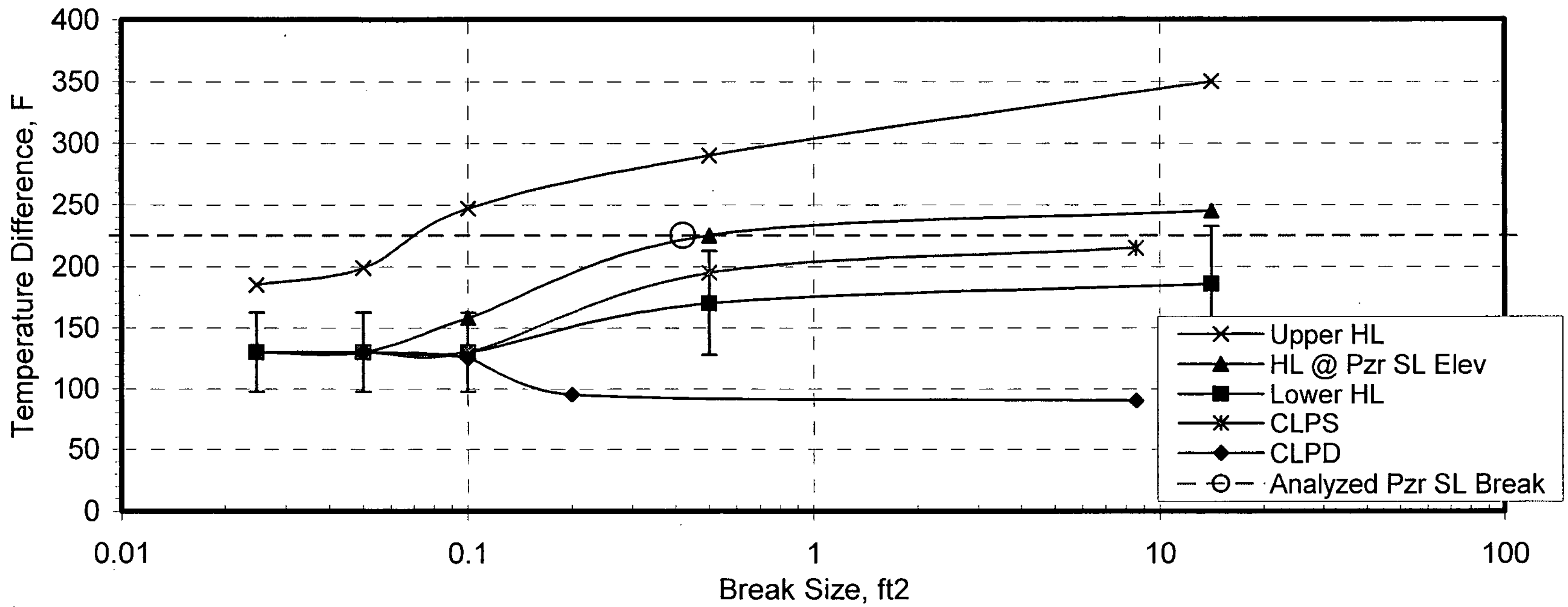
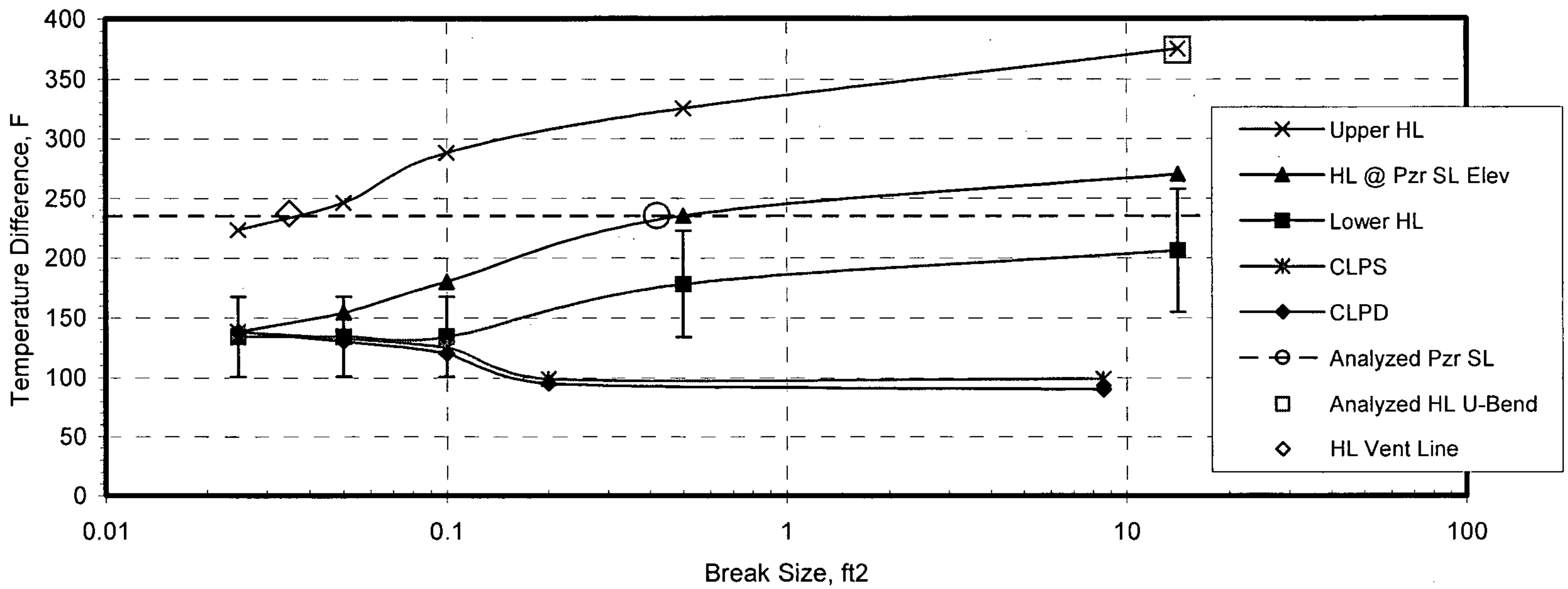


Figure A-22 177-FA Raised-Loop Plant Estimated Maximum Tube-to-Shell Temperature Differences versus Break Size and Location.



Appendix B

Evaluation of Manway/Inspection Opening Failures

The margin bars denote changes from Revision 1

Table of Contents

Evaluation of Manway/Inspection Opening Failures

The B&WOG has evaluated the primary steam generator manway and the inspection opening (handhole) to determine whether their failure should be treated as a loss of coolant accident (LOCA) initiator. This appendix presents a qualitative evaluation showing that a manway/inspection opening failure leading to loss of primary system integrity (e.g., a LOCA) is unlikely.

B.1 Physical Description

As described in Appendix A, the LOCAs of concern from a risk perspective are those in the hot leg (i.e., candy cane) above the surge line. Accordingly, if the failure of a manway or inspection opening (handhole) could initiate a LOCA, only the primary manway and inspection opening in the upper hemispherical head of the steam generator (SG) need to be evaluated. The OTSG upper hemispherical head has a 16-inch ID manway and a 5-inch ID inspection opening (handhole) for access and service. These openings are machined through the SG head with no added reinforcement and clad in the same manner as the internal surfaces of the SG head. Each opening is sealed by a gasket and covered by an austenitic stainless steel backing (diaphragm) plate. A carbon steel cover plate is bolted on to compress the gasket and to contain the primary pressure. The manway cover plate is retained by 16 2-inch diameter low-alloy steel studs and nuts, and the inspection opening cover plate is retained by 12 1-inch diameter low-alloy steel studs and nuts.

The Oconee replacement OTSG (ROTSG) upper hemispherical head has a 16-inch ID manway and a 6-inch ID inspection opening (handhole) for access and service. The openings have integral reinforcement with the forged head. Each opening is sealed by a gasket and covered by an Alloy 690 diaphragm plate. A low alloy steel cover plate is retained by 16 2-inch diameter low alloy steel studs and nuts and the inspection opening cover plate is retained by 8 1¼-inch diameter low alloy steel studs and nuts.

The ANO-1 and TMI-1 replacement OTSGs (known as Enhanced Once-Through Steam Generators, or EOTSGs) also have a primary manway and an inspection opening in the upper hemispherical head. The ANO-1 primary manway is 18-inch ID, and is sealed by a gasket covered by a stainless steel backing plate. A carbon steel cover plate, retained by 20 1-7/8-inch diameter low-alloy steel studs and nuts, is bolted on to compress the gasket and to contain the primary pressure. The TMI-1 EOTSG primary manway is 16-inch ID and is also sealed by a gasket covered by a stainless steel backing plate. A carbon steel cover plate, retained by 16 2-inch diameter low-alloy steel studs and nuts, is bolted on to compress the gasket and to contain the primary pressure. The primary manways have integral reinforcement with the forged head.

The EOTSG inspection opening in both designs is 5-inch ID, and is machined through the head with no added reinforcement. A carbon steel cover plate, retained by 12 1-inch diameter low-alloy steel studs and nuts, is bolted on to compress the gasket and to contain the primary pressure.

B.2 Failure Analysis

Aging effects/degradation mechanisms for each of the components that provide primary pressure boundary integrity have been considered to determine if there is a credible failure mode that could cause a catastrophic breach of the primary pressure boundary resulting in a LOCA. The aging effects identified by the generic license renewal program (GLRP) for the primary manway/inspection opening cover plate, gasket, and backing plate are loss of material (by boric acid wastage due to primary coolant leakage) and loss of mechanical closure integrity. The impact of either of these aging effects would be primary coolant leakage. (The aging effects/degradation mechanisms for the manway/inspection opening studs will be treated separately below.)

Any leakage would be discovered by utility programs as specified by American Society of Mechanical Engineers (ASME) Section XI, Subsection IWB, Examination Category B-P; for all pressure retaining components, it is required that the pressure retaining boundary receive visual and VT-2 examinations during the system leakage and hydrostatic tests following each reactor refueling outage. In addition, each Babcock & Wilcox (B&W) plant has reactor coolant system (RCS) Technical Specification leakage limits and system surveillance requirements that provide reasonable assurance that leakage will be detected and mitigated prior to the complete loss of the primary pressure boundary (e.g., a LOCA). Technical Specifications require plants to shutdown if prescribed leakage limits are exceeded.

The NRC addressed primary coolant leak rates less than Technical Specification limits that could go undetected and which could affect the integrity of the primary coolant pressure boundary in Generic Letter (GL) 88-05 [1]. In response to GL 88-05, each of the B&WOG plants prepared inspection procedures to locate coolant leakage and/or evidence of boric acid corrosion. The basic elements of the various programs used by the B&WOG utilities to monitor for boric acid corrosion meet the intent expressed in GL 88-05.

Therefore, with the combined effect of these three programs:

- Technical Specification leakage limits,
- visual and VT-2 examinations per ASME Section XI Subsection IWB, Examination Category B-P, and
- monitoring for boric acid wastage,

it is unlikely that any loss of material or loss of mechanical closure integrity could go undiscovered to the extent that a failure of the cover plate, gasket, or backing plate could lead to a catastrophic failure of primary system pressure retaining function of the manway or inspection opening (i.e., causing a LOCA). These programs have been deemed acceptable by the NRC as the means for aging management for the manway/inspection opening cover plate, gasket, and backing plate.

The above discussion characterizes all the manway/inspection opening items (parts) except for the studs. The analysis performed for the GLRP identified three failure mechanisms that could lead to the loss of mechanical closure integrity of bolted closures. These mechanisms are: (1) cracking of the studs, (2) loss of stud preload due to stress relaxation, and (3) loss of material specifically for carbon and low alloy steel bolting materials due to boric acid wastage.

To be considered as a LOCA initiator, there must be multiple failures of manway or inspection opening studs to cause a catastrophic breach of the primary system. The failure of one or two studs is not sufficient to cause gross failure. A B&W Owners Group (B&WOG) study was performed for the manway to determine the stresses in adjacent studs as individual studs were assumed to lose their load-carrying capability. This was accomplished using ANSYS finite element models. The models included the cover plate, studs, and interface elements to account for gasket compression. The models were loaded with preload, internal pressure, and steady-state differential thermal expansion stress (normal loading conditions). In successive runs, studs were removed from the model to determine the effect on the stresses in the neighboring studs. The results of the study show that *at least four studs in a row* could be missing on the manway without the remaining studs failing, i.e., with four consecutive studs missing, the remaining studs will not "unzip." Therefore, although leakage is expected, a LOCA will not occur. These results are typical for steam generator access openings and similar results would be expected for the inspection opening studs and for the similar openings on the replacement OTSG.

Therefore, the failure of one or two studs will likely result in leakage of primary coolant. Such leakage should be identifiable via the Technical Specification leakage limit and boric acid surveillance programs. The RCS Technical Specification leakage limit and system surveillance requirements provide reasonable assurance that leakage due to loss of mechanical closure integrity will be detected and mitigated prior to loss of the once-through steam generator (OTSG) pressure boundary function. When such leakage is detected, a root cause evaluation would be performed in accordance with 10 CFR 50, Appendix B, requirement and corrective actions taken to prevent future occurrences. For leaks below the Technical Specification limit, the utility programs to monitor for boric acid corrosion should be effective, as discussed above.

In addition, ASME Section XI, Subsection IWB Examination, Category B-G-2 requires an examination of the bolting (2 inches in diameter and less) associated with the reactor coolant system components. Examination Category B-G-2 provides for visual and VT-1 examinations of bolting surfaces of all the manway and inspection opening studs and nuts at each inspection interval. The visual and VT-1 examinations are intended to identify cracks, wear, corrosion, erosion, or physical damage on the surfaces of the parts. Further, as discussed above, Examination Category B-P of Subsection IWB provides for visual and VT-2 examinations for leakage from pressure-retaining components during system leakage and hydrostatic tests, which also occur at each refueling outage. In accordance with ASME Section XI, IWA-5242, insulation must be removed from pressure-retaining bolted connections for VT-2 examination.

B.2.1 Installation Process

The first two failure mechanisms, stud cracking and stress relaxation, however, could affect multiple studs if the procedure for installing the manway/inspection opening cover was improperly performed, resulting in over-torqued or over-tensioned studs. There are two methods used to install manway/inspection opening cover plates: (1) calibrated torque wrench or (2) hydraulic tensioner. When a calibrated torque wrench is used, the tool operator is required to tighten the nut in a series of passes with the wrench set at increasing torque (ft-lbs) limits. For example, one utility procedure requires five passes, increasing the torque 200-300 ft-lbs for each pass. This process makes the operator more sensitive to the required torque value when adjusting the torque wrench, and reduces the likelihood that the stud will be over- or under-torqued. Hydraulic tensioners fit over some or all of the studs, and apply tension to the studs simultaneously; tension is monitored using a calibrated pressure gauge. For both methods, tension is applied in multiple increments for both inservice and new studs. Properly maintained and calibrated equipment, used according to procedure by trained technicians, assures that the proper tension is applied to the studs.

The following items ensure that a manway/inspection opening is properly installed:

- Training required for the tool operator,
- Maintenance and refurbishing requirements for the equipment,
- Calibration requirements for the equipment,
- Detailed procedure for cover plate installation, and
- A "back-up" process in the procedure to verify proper stud loading.

Operator Training. Each tool operator assigned to install a manway/inspection opening cover (and backing plate and gasket) is required to complete training on a mock-up and demonstrate the ability to perform the required steps with proficiency.

Maintenance and Refurbishing. Maintenance and refurbishing requirements ensure that the equipment used to install the manway/inspection opening cover will be available when needed and work correctly (e.g., be reliable). Quality Assurance (QA) policies that comply with the requirements of 10 CFR 50, Appendix B ensure that measures are established and documented for inspection, test, and operational status of safety-related tools.

Calibration. Proper calibration of equipment ensures that a trained tool operator will apply the correct load on manway/inspection opening studs. The QA Program ensures that tools, gauges, instruments, and other measuring and test equipment used in activities affecting quality are of the range, type, and accuracy to verify conformance to established requirements.

Procedure. The process to install manway/inspection opening cover plates is governed by procedure. The procedure provides a step-by-step process for the proper installation of manway/inspection closures. The procedure provides steps for cleaning each of the components and studholes; installing the gasket, backing plate, and cover plate; and installing and tensioning the studs. Each step requires pertinent data to be recorded by the tool operator, including inspection results, metal-to-metal contact clearances, etc. The procedure for utilities using hydraulic tensioners contains a number of Quality Control (QC)/shift leader hold points/sign-offs to ensure the task is being performed according to procedure. The procedure for utilities using torque wrenches contains either QC hold points/sign-offs, or requires the tool operator to initial completion of *each* step (pass) of the torquing process. Any errors or deviations will be identified and corrected before any substantial amount of work is performed. The task leader also verifies that the appropriately trained personnel are performing the work for which they are qualified.

With the procedural steps required before and during the installation of a manway/inspection opening cover plate, it is not likely that undetected over-torquing/over-tensioning of studs could occur. In addition, as a form of defense-in-depth to ensure that a manway/inspection opening is properly installed, there is a back-up verification process in the procedures that ensures proper stud loading.

Control of over-tensioning/over-torquing. In addition to the detailed procedural instructions, the installation procedure contains a post-installation check to ensure that the load put on the studs is within the appropriate range. There are three techniques used to verify that the proper tension has been placed on the studs:

1. Measuring the relative movement of elongation rods built into the stud. A dial indicator is placed on the top of the stud and is used to read the fraction of thousandths of an inch of indicated elongation. The dial indicator is calibrated to read in units of applied load. These values are recorded by the tool operator and verified with a QC check.

2. Measuring the change in the length of the stud with ultrasonic testing (UT). The length of the stud is "measured" using UT before any tensioning is applied. After the stud is tensioned, the UT is repeated. The device used to perform the UT contains a specially calibrated display to indicate the stud load (in lbs). The acceptable stud loads are indicated in the procedure, and the results of the UT are recorded by the tool operator and verified with a QC check.

3. Performing a redundant post-installation calibration check of the installation equipment. After the manway/inspection opening installation, the calibration of the torque wrench or hydraulic tensioner is rechecked in accordance with the 10 CFR 50 Appendix B requirements.

Each B&WOG utility uses at least one of these verification methods after manway and inspection opening installation. This is in addition to the rigorous utility procedures and preparation for manway and inspection opening installation. Therefore, it is unlikely that via a combination of equipment failures and human errors that the manway or inspection opening studs could be over-tensioned or over-torqued.

B.2.2 Stud Wastage

A failure mechanism of concern is loss of stud material due to boric acid wastage. This concern was generated due to examples of stud damage in the industry, as described in IE Information Notice No. 82-06 [2], and IE Bulletin No. 82-02 [3]. Accordingly, in 1982, the NRC issued Generic Safety Issue (GSI) 29, "Bolting Degradation or Failure in Nuclear Power Plants." GSI-29 was satisfactorily resolved with the implementation of recommended plant-specific bolting integrity programs (required by IE Bulletin 82-02), as suggested in EPRI NP-5769 and NUREG-1339. In Generic Letter 91-17 [4], "Generic Safety Issue 29," the NRC concluded that existing requirements and the ongoing programs should adequately limit the risk from, and minimize the severity of the failure of safety-related bolting. Utilities still follow the bolt integrity programs that were initiated in resolution to GSI-29; for example, these are credited in the Oconee license renewal program.

However, in spite of these programs, for there to be any loss of stud material due to boric acid wastage, leakage of primary coolant would have to occur. As discussed above, leakage would be detectable (and corrected) through either the Technical Specification leakage limits or through the various utility programs to monitor for boric acid wastage (established in response to GL 88-05).

In summary, there are ASME-required inspections of the manway and inspection opening components, Technical Specification leakage limits, programs to monitor for boric acid corrosion, and bolting integrity programs (as a result of GSI-29). These, coupled with conservative design (i.e., multiple studs need to fail), make undetected stud wastage very unlikely. Therefore, it is unlikely that sufficient numbers of manway or inspection opening studs would fail and cause a breach in the primary system (i.e., a LOCA).

B.3 Conclusion

There is no credible failure mode of any of the manway/inspection opening parts (e.g., studs, cover, gasket, backing plate) that could result in a catastrophic failure that would breach the RCS. In particular, multiple failures of studs due to boric acid wastage or improper installation, resulting in over-torquing/over-tensioning are not credible due to the number of utility programs and procedures in place. These programs are currently in effect and will continue to be used by the B&WOG utilities to manage these aging/failure mechanisms for the remainder of plant life. Therefore, it is concluded that a LOCA initiating event via failure of the OTSG or replacement OTSG upper manway or inspection opening is extremely unlikely.

B.4 References

[B-1] Generic Letter (GL) 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Coolant Pressure Boundary Components in PWR Plants," March 1988.

[B-2] IE Information Notice No. 82-06, "Failure of Steam Generator Primary Side Manway Closure Studs," March 1982.

[B-3] IE Bulletin No. 82-02, "Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants," June 1982.

[B-4] Generic Letter 91-17, "Generic Safety Issue 29," October 1991.

Appendix C

Evaluation of RCS Hot Leg Piping

Table of Contents

List of Figures

Evaluation of RCS Hot Leg Piping

C.1 Purpose

The purpose of this Appendix is to show that catastrophic failure of a large-bore hot leg pipe it is extremely unlikely. This is because the Babcock & Wilcox Owners Group (B&WOG) utilities have programs in place to manage the aging effects from all applicable failure mechanisms before there can be a potential for significant damage. This appendix describes the 36-inch ID reactor coolant system (RCS) hot leg piping, the evaluation of applicable failure mechanisms, and the demonstration that plant programs will manage the applicable aging effects so that the pressure boundary function will be maintained during the remaining plant life. The objective is to show that the likelihood a break of the large-bore hot leg piping is remote during the current term of operation, as well as the period of extended operation that may be associated with license renewal.

The summary presented in this Appendix is based on the B&WOG license renewal submittal for RCS Piping, BAW-2243A [C-1], which was approved by the Nuclear Regulatory Commission (NRC) in March 1996. The Topical Report, BAW-2243A, is applicable to all B&WOG operating plants with the exception of Davis-Besse. However, it was determined that the portions of BAW-2243A that address aging of the hot leg piping are applicable to Davis-Besse.

C.2 RCS Hot Leg Piping -- Scope and Construction

The two 36-inch ID hot leg pipes connect the reactor vessel outlet nozzles to the primary inlet nozzles at the top of the once-through steam generators (OTSGs) as shown in Figure C-1. The hot leg straight sections are constructed of seamless carbon steel and clad with austenitic stainless steel or Alloy 82/182 weld deposited overlay. The internal cladding was not considered as pressure retention material in the design. The hot leg piping was designed in accordance with USAS B31.7 Class I piping code, which required compliance to Section IX of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code.

The main coolant hot leg piping contains and is in direct contact with reactor coolant. The water chemistry specifications for reactor coolant during various modes of operation are derived from the B&W Water Chemistry Manual [C-2] and the Electric Power Research Institute (EPRI) Pressurized Water Reactor (PWR) Primary Water Chemistry Guidelines [C-3]. Normal full power operating conditions for the reactor coolant are 555°F in the cold legs and 603°F in the hot legs (design temperature of 650°F) and a system normal operating pressure of approximately 2155 psig (design pressure of 2500 psig). The design flowrate is approximately 133.2×10^6 lbm/h, which results in fluid velocities of approximately 60 ft/sec in the hot legs.

The hot legs were fabricated in the shop in two assemblies: lower hot leg assembly and upper hot leg assembly. Each assembly was fabricated using straight sections and elbows that were fabricated in the shop. A flow element is placed in the upper hot leg assembly of each hot leg to measure flow in each loop. Fabrication details for the elbows, straight sections, and flowmeter element are provided below.

The hot leg elbows are constructed of welded carbon steel plates. Wrought austenitic stainless steel plate was explosively bonded to the carbon steel backing plate prior to plate forming into an elbow half. After plate forming and heat treatment, the two elbow halves were generally welded using the automatic submerged arc (ASA) welding process with full penetration butt-weld longitudinal seams using carbon steel backing strips and typically carbon steel weld consumables. One weld seam is on the elbow extrados and one in the elbow crotch. The back cladding of the elbow welds was typically performed using the shielded metal arc welding (SMAW) process.

The hot leg straight sections are constructed of carbon steel seamless pipe clad with austenitic stainless steel using the ASA welding process. Repairs were generally performed using the SMAW process. Circle seam welds to complete piping subassemblies were typically performed using the ASA welding process or the SMAW process with carbon steel backing rings and carbon steel weld consumables. Back cladding of the circle seam welds was typically performed using austenitic stainless steel employing the SMAW or ASA welding process. Repairs were generally performed using the SMAW process.

A flowmeter assembly is located within each upper hot leg assembly. The carbon steel flowmeter is approximately 38 inches in length with a machined venturi. The 36-inch inlet ID transitions to a 34.740-inch throat ID (Beta ratio = 0.96) and returns to a 36-inch ID. Eight wall-mounted probes are contained within the cylindrical throat to measure total and static pressure. Four wall-mounted probes, with ports facing upstream, are connected to a built-in Alloy 600 manifold ring that has one external pressure connection to measure either total or static pressure, depending upon the flow direction. Four additional wall-mounted probes, with ports facing downstream, are connected to a second built-in Alloy 600 manifold ring. The second manifold ring has a separate external pressure connection. The upstream and downstream probes are offset circumferentially by 45 degrees. The manifold rings are offset axially by approximately 4 inches. Alloy 82/182 cladding is contained within an approximate 9½-inch length section containing the manifold rings. The remainder of the flowmeter assembly is clad with austenitic stainless steel.

The welds in the hot leg piping were subjected to final post-weld heat treatment (PWHT) at 1125°F ± 25°F for 1 hour per inch of weld thickness and, in many cases, subassemblies were subjected to intermediate PWHT (15 minutes minimum) prior to final PWHT. The final PWHT was completed after all welds and cladding were applied to the carbon steel base material.

Radiographic testing (RT) of the welds was performed after either an intermediate or final PWHT. Magnetic particle testing (MT) of the welds and dye penetrant testing (PT) of the cladding were performed after intermediate or final PWHT. The cladding was subjected to ultrasonic testing (UT) for bond. This was performed either before or after PWHT.

Three circle seam field welds were required for each hot leg installation, one at the RV outlet nozzle, one at the OTSG inlet nozzle, and one in the riser between the upper and lower hot leg assemblies (Figure C-1). Field welds were typically performed using the SMAW process. The field welds used to join ferritic piping were backclad with austenitic stainless steel typically using the SMAW process. The non-destructive examination (NDE), i.e., PT and UT, of the austenitic stainless steel backclad was performed following PWHT. Typical locations of the welded joints on the hot leg piping are shown in Figure C-1.

Connections to the hot leg piping include the 12-inch Schedule 140 or 160 decay heat removal branch connection, 10-inch Schedule 140 pressurizer surge line branch connection, one-inch nominal pipe size (NPS) flowmeter, pressure tap connections, the fast response and standard resistance temperature element (RTE) branch connections, and one-inch NPS high point vent branch connections. One surge line branch connection is provided in the hot leg piping for the 10-inch Schedule 140 pressurizer surge line. The hot leg surge line connection is a reinforced two-piece design, consisting of a stainless steel clad carbon steel branch connection and a safe end formed by Alloy 82/182 weld build-up. For Three Mile Island-1 (TMI-1), the safe end is stainless steel.

C.3 Hot Leg Piping -- Effects of Aging

This section discusses the aging effects applicable to the RCS hot leg piping based on the current design and licensing bases of the B&WOG operating plants. The RCS hot leg piping is exposed to RCS water chemistry and stresses associated with Level A (normal) and B (upset) Service Conditions. Management of component aging effects combinations that result from these regularly experienced conditions (i.e., Levels A and B) will ensure that the RCS piping can sustain a Level C (emergency) or D (faulted) event during the current term of operation, as well as the period of extended operation that may be associated with license renewal. The RCS hot leg piping has one component function: to maintain the RCS pressure boundary integrity so that the RCS may continue to perform its system function(s). The impact of the effects of aging on the pressure boundary function is the focus of this section.

The full set of aging effects that could result in loss of the hot leg pressure boundary integrity include cracking (whose stages include crack initiation, controlled crack growth, and through-wall cracking), reduction of fracture toughness, loss of material (thinning), and mechanical distortion and/or ratcheting. The USAS B31.7 Class I design requirements preclude mechanical distortion and/or ratcheting for Level A and B Service conditions through the use of design stress intensity factors for Class I design. Distortion and ratcheting are not considered to be aging effects requiring further consideration for the RCS piping components. Reduction of fracture toughness by irradiation embrittlement and thermal embrittlement are not plausible aging mechanisms since the piping is not within the beltline region of the reactor vessel and carbon steel piping is not susceptible to thermal embrittlement. Cracking and loss of material are the aging effects that will be considered.

C.3.1 Hot Leg Piping -- Clad Carbon Steel Aging Effects

The aging effects to be considered for the clad carbon steel hot leg piping are cracking (initiation, growth, and through-wall) and loss of material. Cracking (initiation and growth) of the carbon steel could occur as a result of pre-service or service-induced flaws. Loss of ferritic material is possible if exposed to a corrosive environment; this could occur as a result of cracking or loss of cladding material, or due to exposure of the external surfaces of the piping to boric acid. The cladding of the main coolant piping is not considered part of the structure in terms of the ability to withstand operating stresses. The aging effects for the clad carbon steel piping are discussed below.

C.3.1.1 Cracking of Ferritic Material Due to Pre-Service or Service-Induced Flaws

The first aging effect to be considered for the clad carbon steel piping is cracking of the ferritic steel (initiation, growth, and through-wall). The main coolant piping is designed to a wide range of loadings that include internal pressure in combination with a spectrum of bending, torsional moments, and axial forces imposed by thermal expansion and by the dead weight of the piping and fluids. In addition, piping installation and assembly procedures may have induced axial stresses in sections of the piping system approaching the material yield strength. Although system operation may modify the stress profiles throughout the piping system, the predominant loadings on piping generally result in maximum stresses in the longitudinal direction. Service loadings may result in growth of pre-existing flaws or induce flaws during the service life of the component.

The most susceptible locations from a structural standpoint for flaw growth are typically the welded joints. Susceptibility of welded joints is attributed to the various constituent zones, i.e., the composite zone, which contains an admixture of filler metal and melted base metal; the unmixed zone, which consists of a boundary of melted base metal that froze before undergoing mixing in the composite zone; and the heat affected zone, which is the portion of the base metal which has been subjected to temperatures high enough to produce solid-state microstructural changes. The various constituent zones result in slight variations in residual stresses and mechanical properties across the welded joint. For example, weld material generally exhibits higher strength and lower toughness than the surrounding base metal. Higher strength of the weld metal results in enhanced load bearing capacity compared to base metal; lower toughness of the weld metal may result in a reduced ability to support structural loads if the weld metal cracks. Cracking (initiation and growth) within the welded carbon steel joints, i.e., circumferential and longitudinal welds, is considered an applicable aging effect due to the potential for pre-service and service-induced flaws.

C.3.1.2 Loss of Ferritic Material Due to Cladding Cracking

The second aging effect to consider is cracking of cladding that could result in exposure of the underlying ferritic steel to a corrosive environment if the crack extends to the base metal. All ferritic base metal and weld metal within the RCS hot leg piping are clad with either austenitic stainless steel or Alloy 82/182. The cladding fabrication processes were carefully controlled to ensure a sound bond between the cladding and the underlying ferritic steel. However, microfissures were detected in stainless steel cladding of selected cold-leg piping sections, i.e., elbows and straights, at Oconee Nuclear Station-1 (ONS-1) prior to startup thus prompting a root cause evaluation. The subsequent evaluation ultimately led to modifications in the cladding fabrication process.

In 1970, sections of ONS-1 RCS cold-leg piping were returned to B&W's Mt. Vernon Works for modifications to accommodate the installation of Westinghouse reactor coolant pumps. In the course of this rework, a routine dye-penetrant examination revealed microfissures in the cladding of a RCP inlet assembly. As a result of finding these microfissures, 100% of the cladding of the ONS-1 RC piping assemblies was dye-penetrant inspected. In addition to several minor surface indications, which were subsequently ground out, more extensive indications were found in both straight and 90° elbow sections. For the straight piping, the clad overlay was applied by multiple electrode submerged arc welding. The cladding on the elbows was applied by explosive bonding.

In selected straight sections of the ONS-1 cold leg piping, microfissures occurred in areas of the cladding with low delta ferrite (generally less than 2.5%). The low ferrite levels were attributed to the use of an improperly manufactured batch of flux in the submerged-arc cladding of these areas only. An adequate ferrite content (depending upon chemical composition of the austenite, but generally about 5%) is necessary to provide hot-cracking resistance. The microfissures were either ground out and repaired or the affected piping sections were replaced. The following manufacturing and quality control processes were revised to preclude future occurrences of hot cracking: (1) a program was instituted where the clad surface of the piping was dye-penetrant checked after every major operation, (2) an intensive operator training program was initiated for using the dye-penetrant technique, and (3) close monitoring of the flux manufacturing operation to ensure homogeneous enrichment of the material with chromium and nickel (i.e., chromium to nickel ratio of 1.9:1), which ensures sufficient ferrite content to preclude hot-cracking in accordance with the Schaeffler diagram.

In selected elbow sections of the ONS-1 piping, the microfissuring was attributed to the corrosive action of acidic etchants used for detection and removal of iron contamination introduced into the cladding surface during elbow fabrication. Shop practice at the time permitted the use of a dilute copper sulfate etchant (Strauss solution) to identify areas of iron contamination. However, evidence suggests that a full-strength Strauss solution may have been inadvertently used on the elbow sections that contained microfissures. This may have been exacerbated by further treatment with 10% nitric acid. The clad material is Type 304 and is slow-cooled from 2000 °F sensitizing the stainless steel cladding. Treatment of this sensitized material with the Strauss solution could cause intergranular attack, seen as microfissures. The following manufacturing and quality control processes were revised to preclude future occurrences: (1) the use of harsh etchants to evaluate the presence of free iron or stainless steel residuals was discontinued, (2) the clad surface of the elbow was dye penetrant inspected after every major operation, (3) an intensive operator program was initiated for the use of the dye penetrant technique, and (4) the clad plate material was changed from Type 304 to 304L, which provided a greater resistance to this type of fissuring.

All defective cladding at ONS-1 was either repaired or replaced thus ensuring the cladding integrity of all main coolant piping at ONS-1. As a result of the lessons learned from ONS-1 and the corrections made to the manufacturing and quality control processes, the integrity of cladding of main coolant piping was ensured for all subsequent contracts thus precluding the existence of pre-service microfissures in the cladding.

Service-induced cracking due to aging may occur as a result of stress corrosion cracking. Aging mechanisms that may lead to cracking for both austenitic stainless steel and Alloy 82/182 cladding are discussed below. Cracking is not a credible aging effect due to the reactor coolant water chemistry requirements.

Stress corrosion cracking (SCC) is cracking of a metallurgically susceptible material under the combined action of stress and corrosion. All three of these "factors" (stress, corrosive environment, and material susceptibility) are necessary to initiate SCC.

1) Tensile stress is required for SCC to occur. As the imposed tensile stress increases, the likelihood of initiation and accelerated propagation of SCC cracking increases. Generally, stresses close to the material yield strength are required in a light water reactor environment to initiate SCC. Stress can be applied (as by operation), can be residual (as from fabrication), or can be a combination of applied and residual.

2) SCC crack initiation also requires exposure to a corrosive environment particular to the material. For example, excessive levels of halogens, oxygen, or sulfates increase the susceptibility of austenitic stainless steels to SCC.

3) For SCC to initiate, the material must be metallurgically susceptible. Chemical composition and metallographic condition affect the susceptibility of a metal to SCC. In some stainless steels and high nickel alloys, slow cooling through the 800-1500 °F temperature range allows the precipitation of chromium carbides at grain boundaries, depleting the area adjacent to the grain boundaries of chromium. This process is termed "sensitization" and renders the material susceptible to SCC.

The cladding of primary system components was exposed to sensitizing conditions during the final stress relief heat treatment of those components. However, a minimum ferrite content for weld overlay cladding was required to preclude hot-cracking and periodically verified during the cladding process. Ferrite levels of weld deposit metal required to preclude hot-cracking also reduce the effects of sensitization since chromium carbide precipitates are attracted to the ferrite rather than to the austenite grain boundaries. Based on the manufacturing requirements for ferrite levels to preclude hot-cracking and the reactor coolant chemistry requirements (e.g., hydrogen overpressure and limits on halogens and oxygen), primary system weld deposit cladding is not susceptible to SCC.

The cladding for the main coolant piping elbows is Type 304 or 304L austenitic stainless steel plate. The elbows were subjected to sensitizing temperatures during fabrication and PWHT. As discussed above, intergranular microfissures were detected in selected elbows at Oconee Unit 1 and were subsequently ground out and repaired. The root cause evaluation traced the problem to harsh chemical etchants used to detect impregnated iron and stainless steel residuals on the surface of the cladding following the forming of the elbows. Manufacturing and NDE procedures were revised to preclude subsequent occurrences. SCC of the clad elbows is not credible because of the reactor coolant chemistry requirements (e.g., hydrogen overpressure and limits on halogens and oxygen).

In addition, B&W extensively tested Type 304 austenitic stainless steels exposed to typical RCS boric acid solutions. The tests included low temperature beaker tests, boiling beaker tests, autoclave tests, and dynamic loop tests at temperatures between 220 °F and 650 °F. Both annealed and sensitized U-bend stainless steel specimens, which were stressed to 75% of the material yield strength, were tested. Test results indicated extremely low corrosion rates and no evidence of stress corrosion cracking.

Reactor coolant chemistry controls are in place, as required by plant Technical Specifications, to prevent the coolant from becoming an environment favorable to SCC. Dissolved oxygen, halides, and other impurities in the primary coolant are monitored by plant surveillance testing in accordance with plant Technical Specifications (typically every 72 hours or 3 days/week), and are maintained in accordance with the EPRI PWR Primary Water Chemistry Guidelines for all modes of operation at all participating utilities. Corrective action is required by plant procedures or Technical Specifications if the specified limits are exceeded. Actual dissolved oxygen concentrations are usually maintained below 5 ppb by applying a hydrogen overpressure to the coolant system (25-50 cc/kg H_2O). During shutdown, the aerated primary coolant may contain as much as 8 ppm dissolved oxygen, but is below the temperature range where SCC is typically observed. SCC of austenitic stainless steel cladding is not credible because with the above chemistry controls (i.e., a properly managed primary system), an environment conducive to SCC does not exist.

Alloy 82/182 is the weld analogue to Alloy 600. Since the use of Alloy 82/182 as a cladding in B&W 177-FA plants is very limited and not generally examined, operational information is not available. It was demonstrated, however, in a number of tests and evaluation efforts that Alloy 600 is subject to primary water SCC (PWSCC). The extent of susceptibility is dependent upon many factors including chromium and carbon content, thermal treatment, and applied stress. The condition of the Alloy 82/182 cladding in the flowmeter element is not known with regard to these factors; it is concluded that the Alloy 82/182 cladding may be susceptible to PWSCC, which may lead to loss of ferritic material in the unlikely event that the crack extends into the base metal. Section C.4.2 describes the B&WOG utility programs that manage this aging effect (PWSCC) before it can cause significant damage.

In the review of aging mechanisms capable of causing surface cracking of cladding, it was determined that cracking of the Alloy 82/182 weld deposit may be possible due to PWSCC. However, it is unlikely that cracking of the Alloy 82/182 cladding of the main coolant piping could extend into the base metal since the aging mechanisms that could cause sustained crack growth (e.g., thermal embrittlement which is not plausible since operating temperatures are below the 400°C to 500°C embrittlement threshold for high chromium steels) are not significant and the cladding of the main coolant piping is not considered part of the structure in terms of the ability to withstand operating stresses. However, surface cracking of the Alloy 82/182 main coolant piping cladding, which could lead to loss of underlying ferritic material, is conservatively assumed to be an applicable aging effect. Section C.4.2 describes the B&WOG utility programs that manage this aging effect (surface cracking) before it can cause significant damage.

C.3.1.3 Loss of Ferritic Material due to Loss of Cladding Material

The third aging effect to consider is loss of ferritic material due to loss of cladding material. Two general categories of aging mechanisms affect the likelihood that significant cladding material loss will occur. These are erosion-corrosion and various other types of corrosion (crevice, pitting, and general). This section discusses the materials and conditions that are necessary to enable their initiation and the likelihood that the cladding is susceptible to degradation by these mechanisms.

Erosion is the loss of material due to forces created by a flowing fluid. Material loss due to erosion in the RCS is possible only if the RCS fluid contains particulates in the fluid stream that impinge upon the surface of the cladding. Regions of the RCS that would be susceptible to this type of erosion might include those locations that experience high fluid velocities and changing flow directions such as elbows (e.g., hot leg 180 degree U-bend). The reactor coolant water chemistry and filtration requirements preclude the buildup of particulates that could contribute to abrasive erosion of cladding material. Particulates and dissolved solids are removed through the makeup and purification system, which typically processes an entire RCS volume during each day of operation. Main coolant piping fluid velocities of 50 to 60 ft/s are not expected to cause erosion of the cladding surfaces since the reactor coolant does not contain particulates that could lead to abrasive erosion. Loss of cladding due to erosion is not an applicable aging effect for the current term of operation, as well as the period of extended operation that may be associated with license renewal.

Erosion-corrosion is the loss of material due to the combined actions of erosion by a flowing fluid and corrosion of the newly exposed base material by the flowing fluid. Protective oxide films provide resistance to erosion-corrosion; mechanical removal or dissolution of the film exposes the surface to further film production. Repetition of this process leads to thinning of the base metal. The extent of erosion-corrosion is influenced by (1) fluid flow velocity, (2) fluid temperature and chemistry, and (3) material susceptibility. The stainless steels and nickel-based steels used as cladding are not susceptible to corrosion and are considered resistant to erosion/corrosion in a PWR environment.

General corrosion (also known as uniform corrosion) is the uniform attack of a metal surface resulting in material dissolution and sometimes corrosion product buildup. Austenitic stainless steel and Alloy 82/182 are resistant to general corrosion. General corrosion of the primary system cladding is not an applicable aging effect for the current term of operation, as well as the period of extended operation that may be associated with license renewal.

Pitting and crevice corrosion are generally associated with stagnant or low flow conditions. Pitting corrosion can be considered a special instance of crevice corrosion in that when a pit is formed, it essentially becomes a crevice. Corrosion in crevices may be caused by (1) an increase in metal ion concentration within the crevice as compared with the concentration outside the crevice (concentration cell corrosion), (2) a decrease in oxygen concentration inside the crevice (oxygen concentration cell corrosion), or (3) increased corrodent activity resulting from the accumulation of corrosion products within the crevice (stagnant area corrosion). All three of these mechanisms are the result of restricted fluid circulation through the crevice. Restrictions on halogens and oxygen content have been found to contribute significantly to the control of the aforementioned mechanisms that cause pitting and crevice corrosion. It is not credible that the conditions necessary for crevice or pitting corrosion of stainless steel and Alloy 82/182 cladding exist even in stagnant or low flow areas.

In the above review of aging mechanisms capable of causing ferritic material loss due to loss of cladding material, it was determined that loss of ferritic material due to loss of cladding material is not an applicable aging effect for the current term of operation, as well as the period of extended operation that may be associated with license renewal.

C.3.1.4 Loss of Ferritic Material due to Boric Acid Wastage

The last aging effect to be considered is external wall thinning due to boric acid wastage. The leakage of PWR primary coolant through adjacent bolted closures, and the subsequent evaporation and re-wetting cycles, can lead to the presence of a boric acid slurry on the external surfaces of the clad carbon steel piping. These alternate wetting and drying cycles can cause very high corrosion rates. Therefore, loss of material through external wall thinning due to boric acid wastage is an applicable aging effect for the clad carbon steel piping. Section C.4.2 describes the B&WOG utility programs that manage this aging effect (loss of material through external wall thinning due to boric acid wastage) before it can cause significant damage.

C.3.1.5 Summary of Applicable Aging Effects

In summary, there are three applicable aging effects requiring programmatic management for the clad carbon steel hot leg piping: (1) cracking of the carbon steel welded joints, (2) loss of material on the external surfaces of the piping due to boric acid corrosion due to leakage, and (3) loss of ferritic material in the hot leg flow meter assembly due to cracking of the Alloy 82/182 cladding. Section C.4.2 describes the B&WOG utility programs that manage these aging effects before they can cause significant damage.

C.3.2 RCS Piping Performance History

For the historical review of RCS piping, a review of the Nuclear Plant Reliability Data System (NPRDS), Licensee Event Reports from July 1974 through March 1994, and NRC Generic Communications -- Information Notices (IN), Circulars (CR), IE Bulletins (BL), and Generic Letters (GL) -- through January 1995 was performed to identify past incidents of aging effects applicable to Class 1 piping. This review identified cracking of piping due to mechanical and other causes and loss of material (external) as applicable aging effects for the hot leg piping. Details of the operating history review are provided in BAW-2243A [C-1]. See also Section 3.4.3.1 of the main report.

C.4 Demonstration of Aging Management

The aging management review is performed by demonstrating that the applicable aging effects, as identified in the Section C.3, can be managed by existing programs. Demonstration of aging management is accomplished by establishing a clear relationship among,

1) the items under review,

2) the aging effects on these items caused by the material-environment-stress combinations which, if undetected, could result in the loss of the RCS piping pressure boundary function such that the RCS could not perform its system function(s), and

3) the credited aging management programs whose actions serve to preserve the RCS intended function(s).

The purpose of this section is to describe the existing programs that are credited for managing the applicable aging effects and to provide justification as to why the technical elements adequately manage aging.

C.4.1 Aging Management Programs

As background, the aging management programs primarily credited within this section fall under ASME Section XI, Technical Specifications, and commitments to generic NRC communications. Some general background on these program groups credited for aging management is provided in the following sections.

ASME Section XI ISI and IST

The regulatory basis for providing an inservice inspection/testing program to verify RCS integrity is found in 10 CFR 50.55a(g), which specifically requires ISI and IST in accordance with ASME B&PV Code Section XI, and 10 CFR 50.36(c)(3), which provides general surveillance requirements. In addition, Technical Specifications specifically require both ISI and IST. Plant-specific Technical Specifications may specify which edition of Section XI of the Code will be effective for the initial inspection period. As required by 10 CFR 50.55a, every 120 months the Inservice Inspection (ISI) Plan is reviewed and revised to meet the latest NRC-authorized edition of the ASME B&PV Code. This revision is submitted to the NRC for approval. At present, the approved references to Section XI in 10 CFR 50.55a include addenda through the 1988 Addenda and editions through the 1989 Edition. Mandatory Appendix VII (Qualification of Nondestructive Examination Personnel for Ultrasonic Examination) is required when referencing the 89 Edition; however, mandatory Appendix VIII (Performance Demonstration for Ultrasonic Examination Systems) was first introduced in the 1989 Addenda.

The ASME Code Section XI requirements for inservice inspection of the hot leg piping are shown in Table IWB 2500-1, Examination Categories B-F, B-J, and B-P, of the 1989 Edition of ASME Section XI, including mandatory Appendices VII and VIII, with Appendix VIII in accordance with 1989 Addenda.

Technical Specifications

The aging management elements contained in the plant Technical Specifications include primary leakage limits and system surveillance requirements. The Technical Specifications also include primary chemistry requirements. All of these measures provide a defense-in-depth strategy against aging effects that can lead to loss of RCS piping pressure boundary integrity such that the RCS intended functions could be defeated.

Commitments to NRC Generic Communications

Commitments to NRC generic communications are credited for managing loss of material by boric acid wastage in accordance with Generic Letter 88-05 (Boric Acid Corrosion of Carbon Steel Reactor Coolant Pressure Boundary Components in PWR Plants).

C.4.2 Main Coolant Piping -- Clad Carbon Steel

As discussed in Section C.3.1, the applicable aging effects that could manifest themselves in the clad carbon steel hot leg piping include cracking at welded joints, loss of external ferritic material due to boric acid wastage, and loss of ferritic material in the hot leg flowmeter assembly due to cracking of the Alloy 82/182 cladding. Loss of external ferritic material due to boric acid wastage is managed by commitments to Generic Letter 88-05. Aging management of loss of ferritic material due to cracking of the Alloy 82/182 cladding in the hot leg flowmeter piping is managed by the B&WOG and plant-specific Alloy 600 program. Cracking at welded joints is managed by a combination of several existing programs. ASME Section XI Subsection IWB Examination Category B-J (or B-J as modified by Code Case N-560 to incorporate risk-informed inspection), for pressure retaining welds in piping, requires that both a surface and a volumetric examination be performed on selected welded joints in the clad carbon steel hot leg piping. Indications that exceed acceptance criteria can be either analyzed, in order to justify continued operation; repaired, in accordance with Code procedure; or the component can be replaced. Specific inspection locations are identified for each plant in their plant-specific inservice inspection plan.

Another existing program that will serve to manage weld cracking falls under ASME Section XI Subsection IWB, Examination Category B-P, which provides for visual (VT-2) examination associated with system leakage and hydrostatic testing. The code prescribes varying test conditions during which the VT-2 examination is conducted. A system leakage test is conducted with no required holding time at normal system operating pressure and temperature. A hydrostatic test requires a four-hour holding time for insulated lines and 10 minutes for uninsulated lines at predetermined pressures and temperatures. Corrective measures are included in IWA-5250 to deal with detected leakage in accordance with the acceptance standards of IWB-3142. However, the use of Code Cases 498 and 498-1 allows utilities to perform system leakage tests in lieu of hydrostatic tests as approved by the NRC on a plant-specific basis.

C.5 Conclusions

The foregoing evaluation demonstrates that the B&WOG utilities have programs in place, as described in Section C.4.2, to manage aging effects before the applicable failure mechanisms present a potential of significant damage. Therefore, it is extremely unlikely that a catastrophic failure of large-bore hot leg pipe will occur. The effects of aging on the hot leg piping will be managed so that the RCS pressure boundary function will be maintained consistent with the current licensing basis during the current term of operation, as well as the period of extended operation that may be associated with license renewal.

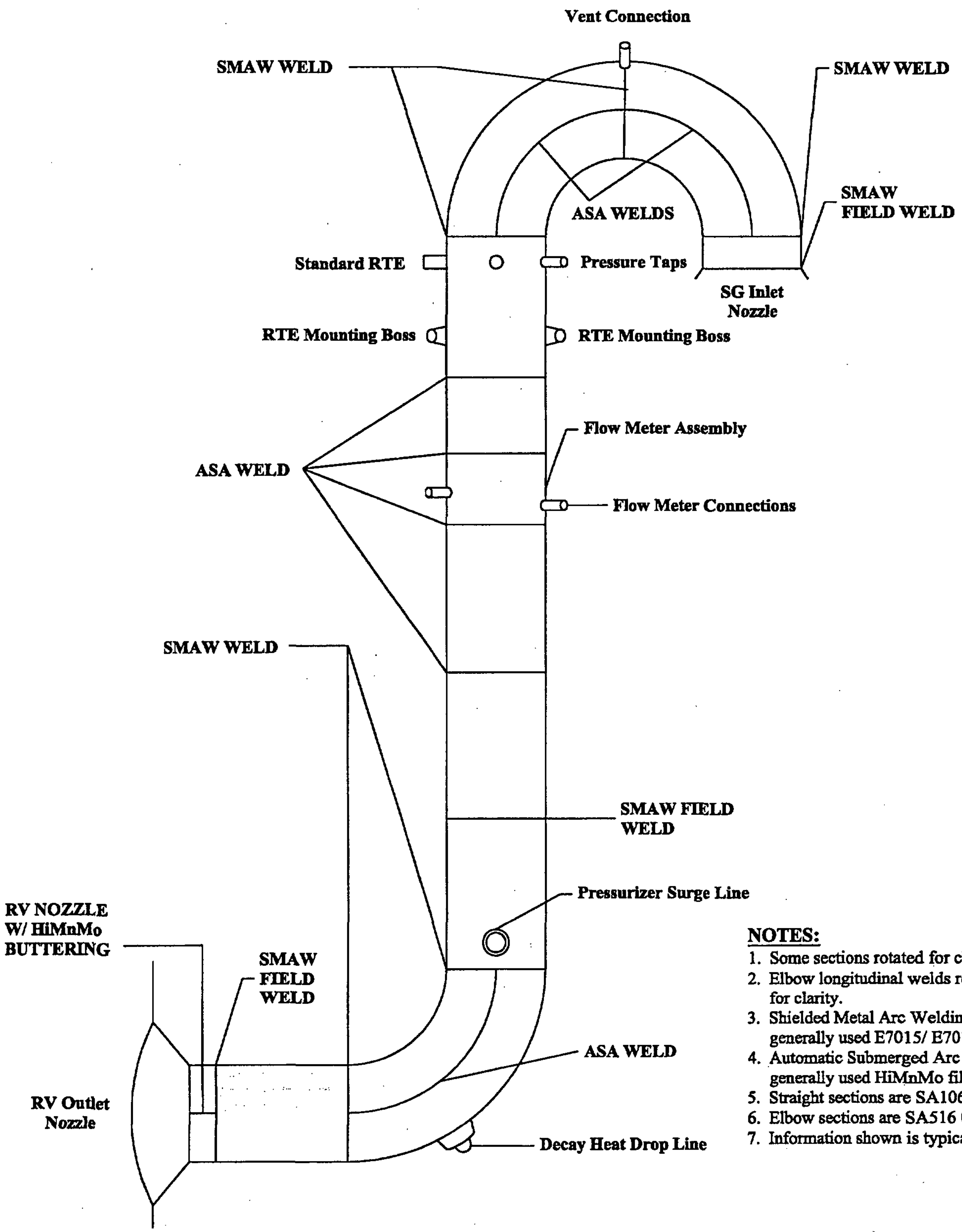
C.6 References

[C-1] FTI Topical Report BAW-2243A, "The B&W Owners Group Generic License Renewal Program, Demonstration of the Management of Aging Effects for the Reactor Coolant System Piping," June 1996.

[C-2] J. H. Hicks, D. W. Koch and L. S. Lawrence, "B&W Water Chemistry Manual for 177 FA Plants," BAW-1385, Revision 5, January 1990.

[C-3] Electric Power Research Institute, "Pressurized Water Reactor (PWR) Primary Water Chemistry Guidelines," Revision 3, EPRI-TR-105714, November 1995.

Figure C-1 - Hot Leg Piping



NOTES:

1. Some sections rotated for clarity.
2. Elbow longitudinal welds rotated 90 degrees for clarity.
3. Shielded Metal Arc Welding (SMAW) welds generally used E7015/ E7018 electrodes.
4. Automatic Submerged Arc (ASA) welds generally used HiMnMo filler material.
5. Straight sections are SA106 Gr. C.
6. Elbow sections are SA516 Gr. 70.
7. Information shown is typical.

Appendix D

Review and Evaluation of 10 CFR 50, Appendix A "General Design Requirements for Nuclear Power Plants" for Steam Generator Loads From Postulated Breaks in Large-Bore Piping

Table of Contents

Review and Evaluation of 10 CFR 50, Appendix A "General Design Requirements for Nuclear Power Plants" for Steam Generator Loads From Postulated Breaks in Large-Bore Piping

D.1 Purpose

The purpose of this review and evaluation is to determine if an exemption from 10 CFR 50, Appendix A, "General Design Criteria for Nuclear Power Plants," pursuant to 10 CFR 50.12, "Specific Exemptions," is required in order for the Nuclear Regulatory Commission (NRC) to approve this request from the Babcock & Wilcox-type nuclear power plants to establish a risk-informed basis for acceptability of thermal loads on OTSG tubes, tube repair products, and tube-to-tubesheet joints from large-bore upper hot leg pipe break.

D.2 Background

All operating Babcock & Wilcox-type plants were licensed based on the results of Topical Report BAW-10027 [D-1], "Once-Through Steam Generator Research and Development Report," which determined, under then-current testing methods, the large break loss-of-coolant accidents (LBLOCA) loads on the OTSG internals were bounded by the main steam line break (MSLB) loads. Furthermore, the LBLOCA loads under which the plants' OTSGs were initially licensed were dynamic loads and did not include thermal-hydraulic loads.

Since the original operating licenses were issued, OTSG tube repair methods (such as sleeving or re-rolling tubes into the tubesheet) have been qualified by the licensees (and licensed by the NRC) using loads determined from current analyses. Some tube repair method qualifications considered thermal loads from a hot leg reactor vessel exit large-bore pipe break. However, repair methods have also been qualified without considering the large-bore pipe break loads, using loads from reactor coolant system (RCS) attached pipe breaks and MSLB loads as the repair qualification loads. In their Safety Evaluations of the qualification reports, the NRC typically cited General Design Criterion (GDC) 14, "Reactor Coolant Pressure Boundary," and Draft Regulatory Guide (RG) 1.121 [D-2], "Bases for Plugging Degraded PWR Steam Generator Tubes." Draft RG 1.121, in turn, cites GDC 14, "Reactor Coolant Pressure Boundary," GDC 15, "Reactor Coolant System Design," and GDC 32, "Inspection of Reactor Coolant Pressure Boundary," in its introduction.

The following review and evaluation determines if an exemption from any of the 10 CFR 50 Appendix A, "General Design Criteria for Nuclear Power Plants," is required in order for the NRC to approve the Babcock & Wilcox Owners Group (B&WOG) request.

D.3 Review and Evaluation

D.3.1 How the Applicable GDC are Met

The B&WOG has prepared this Topical Report to present an alternate, risk-informed basis for the acceptability of thermal loads on OTSG tubes, tube repair products, and tube-to-tubesheet joints induced by a loss of coolant accident (LOCA) in the large-bore piping of the RCS upper hot leg. The basis for the requested change is that the thermal loads from a break in upper hot leg large-bore piping, and the subsequent possibility of induced steam generator tube rupture, represent a very small risk per the probabilistic and deterministic guidance of Regulatory Guide 1.174. Therefore, acceptability of OTSG thermal loads with respect to meeting deterministic licensing basis requirements for tubes, tube repair products and tube-to-tubesheet joints, will be based on the other limiting accidents, rather than upper hot leg large-bore pipe break. For the purpose of meeting the intent of the GDC, the limiting postulated accident with respect to the thermal loads on OTSG tubes, tube repair products, and tube-to-tubesheet joints, is either a LOCA in RCS attached pipe or main steam line break (MSLB).

The B&WOG reviewed 10 CFR 50 to determine if an exemption, pursuant to 10 CFR 50.12, is needed in order for the NRC to approve the requested change to the OTSG licensing basis. The review concluded that no exemption is required; however for the purpose of meeting the intent of the GDC, this topical Report provides a alternate, risk-informed basis for acceptability of the thermal loads on OTSG tubes, tube repair products, and tube-to-tubesheet joints from large-bore upper hot leg pipe break. Specific applicable GDC are discussed in the sections of this appendix presented below.

Section 2.2 of this Topical Report discusses how other aspects of the licensing basis are met with respect to the proposed change to the licensing basis.

D.3.2 Regulatory Basis

10 CFR 50, Appendix A, "General Design Criteria for Nuclear Power Plants," became effective on May 21, 1971 (36 FR 3255). For plants that were issued construction permits prior to this date, the NRC did not make the General Design Criteria (GDC) retroactive and plants were not required by regulation to incorporate these GDC into their licensing bases [D-3]. All operating plants of the B&WOG were issued construction permits prior to May 21, 1971, and, therefore, the GDC are not applicable as a regulation to these plants. Nonetheless, the B&WOG has performed this review and evaluation to determine if an exemption under 10 CFR 50.12 would be warranted even if the GDC were applicable as a regulation. The replacements of OTSGs are component replacement activities under the requirements of 10CFR50.55a, "Codes and Standards" and ASME Boiler and Pressure Vessel (B&PV) Code Section XI, Article IWA-4000, "Repair and Replacement." As a result, replacement OTSGs must meet the applicable Construction Code Edition, Addenda, and Code Cases and Section XI, and are also not subject to 10 CFR 50, Appendix A as a regulation.

D.3.3 Methodology

To evaluate the need for an exemption as if the GDC of 10 CFR, 50 Appendix A were applicable as a regulation, the GDC were reviewed by: 1) identifying the criteria that specify "loss of coolant accident(s)" and then evaluating their application to the OTSG loads, and 2) evaluating the NRC-cited GDC 14, GDC 15, and GDC 32 with respect to the OTSG loads. Next, the remaining GDC were reviewed, with special attention provided to those criteria that have been historically referenced in NRC and industry documents on steam generators. These evaluations determined if the GDC was a candidate for an exemption pursuant to 10 CFR 50.12 as a result of not applying large-bore pipe break loads to the OTSG design.

D.3.4 GDC Specifying LOCAs

The following GDC specify the term "loss of coolant accident(s):"

4 – "Environmental and Dynamic Effects Design Bases"
17 – "Electric Power Systems"
19 – "Control Room"
38 – "Containment Heat Removal"
46 – "Testing of Cooling Water System"
50 – "Containment Design Basis"
64 – "Monitoring Radioactivity Releases"

GDC 4 - "Environmental and Dynamic Effects Design Bases" requires that structures, systems, and components (SSCs) important to safety be designed to accommodate the effects of and be compatible with the environmental conditions associated with postulated accidents, including "loss of coolant accidents." The existing environmental qualification of SSCs, which includes qualification for LBLOCA effects, will be unaffected by the B&WOG request.

This GDC also requires SSCs to be appropriately protected against the dynamic effects of a pipe rupture (e.g., the dynamic effects resulting from a LBLOCA). The GDC allows the dynamic effects associated with pipe ruptures to be excluded from the design basis when analyses, reviewed and approved by the NRC, demonstrate the probability of fluid system piping rupture is extremely low. The thermal loads on OTSG tubes associated with a large-bore pipe break are thermal-hydraulic loads as a result of transient conditions (i.e., tube-to-shell temperature difference caused by the full length of the tubes being exposed to relatively cold injection flow) and not dynamic effects.

Therefore, since the environmental qualification of SSCs will not be affected, and the OTSGs are affected by thermal loads following a LOCA and not the dynamic effects of a LOCA, this GDC is not a candidate for a 10 CFR 50.12 exemption. Compliance with this GDC is unaffected by the B&WOG request.

GDC 17 – "Electric Power Systems" specifies that following "a loss of coolant accident" electrical power circuits shall be available to ensure core cooling, containment building integrity, and other vital safety functions are maintained. This GDC concerns the assurance of electrical power and is not affected by the OTSG loads. Therefore, this GDC is not a candidate for a 10 CFR 50.12 exemption. Compliance with this GDC is unaffected by the B&WOG request.

GDC 19 – "Control Room" requires a control room be provided from which actions can be taken to operate the nuclear power plant safely and to maintain it in a safe condition under accident conditions, including "loss of coolant accidents." This GDC's LOCA considerations are addressed by locating the necessary controls for safely operating and shutting down the plant within the control room, and by protecting the operating crew in the control room from radiation by means of shielding, special ventilation systems, and control room leak tightness. The control room design GDC is not affected by the OTSG loads and, therefore, is not a candidate for a 10 CFR 50.12 exemption. Compliance with this GDC is unaffected by the B&WOG request.

GDC 38 – "Containment Heat Removal" requires the provision of a system to remove heat from the reactor containment. The GDC specifies that the system be able to rapidly reduce the containment pressure and temperature following a "loss of coolant accident." This GDC is addressed by systems such as the containment building spray system and containment building air cooling system, and is not affected by the OTSG loads. Therefore, GDC 38 is not a candidate for a 10 CFR 50.12 exemption. Compliance with this GDC is unaffected by the B&WOG request.

GDC 46 – "Testing of Cooling Water System" requires the design of the plant cooling water system to allow periodic pressure and functional testing under conditions as close as practical to the performance of the full operational sequence that brings the system into operation for reactor shutdown and for "loss of coolant accidents." This GDC is addressed by the design of the cooling water system to allow testing, and is unaffected by the OTSG loads. Therefore, GDC 46 is not a candidate for a 10 CFR 50.12 exemption. Compliance with this GDC is unaffected by the B&WOG request.

GDC 50 – "Containment Design Basis" requires the containment building structure and its internal compartments accommodate, without exceeding the containment building's design leakage rate, the pressure and temperature conditions resulting from a "loss of coolant accident." This GDC is addressed by the structural design of the containment building. The containment building spray system and containment building air cooling system are also typically credited for preventing overpressurization of the containment building. The OTSG tubes, one of several barriers to fission products, are not part of the containment building structure design. Therefore, GDC 50 is not a candidate for a 10 CFR 50.12 exemption. Compliance with this GDC is unaffected by the B&WOG request.

GDC 64 – "Monitoring Radioactivity Releases" requires monitoring the containment building atmosphere, spaces containing components for recirculation of "loss of coolant accident" fluids, effluent discharge paths, and the plant environs for radioactivity. Radiation and radioactivity monitoring systems address this GDC, which are not affected by the OTSG loads. Therefore, this GDC is not a candidate for a 10 CFR 50.12 exemption. Compliance with this GDC is unaffected by the B&WOG request.

D.3.5 NRC-Cited GDC

The following addresses the three GDC cited by the NRC in their evaluations of OTSG tube repair methods.

GDC 14 – "Reactor Coolant Pressure Boundary" has been typically cited by the NRC when determining whether an OTSG repair method is qualified. GDC 14 requires the reactor coolant pressure boundary to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture.

Primary-side to secondary-side leakage in the OTSGs is monitored to determine the trending of any abnormal OTSG tube leakage. Tube crack indications are characterized and removed from service, if warranted. This risk-informed Topical Report demonstrates that there is an extremely low frequency of a break occurring in the large-bore piping of the reactor coolant system (and an extremely low risk to the public even if rupture of the OTSG tubes is assumed to occur as a result of such a break). Therefore, this GDC is addressed by the results demonstrated in this Topical Report, which is limited to the OTSG design, and is not a candidate for a 10 CFR 50.12 exemption.

GDC 15 – "Reactor Coolant System Design" requires the reactor coolant system to be designed with sufficient margin to assure the design conditions of the reactor coolant system boundary are not exceeded during any condition of "normal operation, including anticipated operational occurrences." The subject of this review and evaluation is OTSG loads resulting from "loss of coolant accidents" and not from "normal operation" or "anticipated operational occurrences" as addressed by the GDC. Therefore, this GDC is not a candidate for a 10 CFR 50.12 exemption. Compliance with this GDC is unaffected by the B&WOG request.

GDC 32 – "Inspection of Reactor Coolant System Boundary" requires the reactor coolant system boundary be designed to permit periodic inspection and testing to assess the structural integrity and leak tight integrity, and the reactor pressure vessel to have an appropriate surveillance materials program. These inspection and testing design requirements are unaffected by the OTSG loads. Therefore, this GDC is not a candidate for a 10 CFR 50.12 exemption. Compliance with this GDC is unaffected by the B&WOG request.

D.3.6 Remaining GDC

The remaining GDC not listed above were also reviewed for this evaluation. This review identified the use of the term "postulated accident(s)" in several GDC for designing structures, systems, and components. For example, GDC 31, "Fracture Prevention of Reactor Coolant Pressure Boundary," requires the pressure boundary to be designed with respect to "postulated accident conditions."

"Postulated accident(s)" are not specific accidents for a particular GDC where it is used, but rather those accidents that are determined as credible for the plant design. This risk-informed Topical Report demonstrates that the accident scenarios involving a break in the large-bore piping of the RCS upper hot leg and consequential OTSG tube rupture are of very small risk. Pursuant to the guidelines of Regulatory Guide 1.174, this Topical Report provides a alternate, risk-informed basis for acceptability of the thermal loads on OTSG tubes, tube repair products, and tube-to-tubesheet joints induced by an upper hot leg large-bore pipe break. Therefore, for the purpose of meeting the GDC with respect to the thermal loads on OTSG tubes, tube repair products, and tube-to-tubesheet joints, the limiting "postulated accident" is a LOCA in RCS attached pipe or MSLB.

The following GDC are discussed because these GDC have historically been referenced in industry and NRC documents concerning steam generators, and are not specifically addressed above:

GDC 1 – "Quality Standards and Records" requires structures, systems, and components important to safety be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed. This GDC concerns ensuring quality standards are met and is irrespective of the specific accident loads being used by the OTSG design. Therefore, this GDC is not a candidate for a 10 CFR 50.12 exemption. Compliance with this GDC is unaffected by the B&WOG request.

GDC 2 – "Design Bases For Protection Against Natural Phenomena" requires structures, systems, and components important to safety be designed to withstand the effects of natural phenomena without the loss of capability to perform their safety function. These natural phenomena design requirements are to be met irrespective of the specific accident loads being used by the OTSG design. Therefore, this GDC is not a candidate for a 10 CFR 50.12 exemption. Compliance with this GDC is unaffected by the B&WOG request.

GDC 30 – "Quality of Reactor Coolant Pressure Boundary" requires components that are part of the reactor coolant pressure boundary be designed, fabricated, erected, and tested to the highest quality standards practical. Means are to be provided for detecting and, to the extent practical, identifying the location of the source of reactor coolant leakage. Maintaining the highest quality standards practical and providing means for detecting and identifying reactor coolant leakage are to be met irrespective of the specific accident loads being used by the OTSG design considerations. Therefore, this GDC is not a candidate for a 10 CFR 50.12 exemption. Compliance with this GDC is unaffected by the B&WOG request.

GDC 35 – "Emergency Core Cooling" requires a system to provide abundant emergency core cooling following a loss of reactor coolant, with suitable redundancy in components and features, and suitable interconnections, leak detection, isolation, and containment capabilities to assure that the safety function can be accomplished, assuming a single failure. The upper hot leg large-bore pipe break scenario cannot produce high OTSG tube loads unless there is "abundant" emergency core cooling system flow. This risk-informed Topical Report demonstrates that the accident scenarios involving a break in the large-bore piping of the RCS upper hot leg and consequential OTSG tube rupture present a "very small" risk pursuant to the guidelines of Regulatory Guide 1.174. This Topical Report also demonstrates that the defense-in-depth principles discussed in Regulatory Guide 1.174 are preserved, in the unlikely event that OTSG tube rupture occurs. Therefore, this Topical Report provides a alternate, risk-informed basis for acceptability of the thermal loads on OTSG tubes, tube repair products, and tube-to-tubesheet joints induced by an upper hot leg large-bore pipe break. Consequently, for the purpose of meeting the GDC with respect to the thermal loads on OTSG tubes, tube repair products, and tube-to-tubesheet joints, the limiting "postulated accident" is a LOCA in RCS attached pipe or MSLB.

D.4 Conclusion

The operating B&WOG plants were all issued construction permits prior to the effective date of 10 CFR 50, Appendix A and, therefore, the GDC do not apply as a regulation to these plants (consequently an exemption would not be required in order to deviate from these requirements). Replacement OTSGs are replacement components under 10 CFR 50.55a and ASME B&PV Code Section XI, and therefore, must meet the applicable Construction Code Edition, Addenda, and Code Cases, and Section XI (i.e., 10 CFR 50, Appendix A does not apply as a regulation to these replacement components).

Nonetheless, the B&WOG has reviewed and evaluated the GDC with respect to the B&WOG request to base acceptability of OTSG thermal loads upon the existing RCS attached pipe LOCA and MSLB accident analyses rather than on the thermal loads from a large-bore upper hot leg pipe break. Based on the results of this review and evaluation, it is concluded that even if the GDC were applicable as a regulation, a 10 CFR 50.12 exemption would not be required from any of the criteria of 10 CFR 50, Appendix A, "General Design Criteria for Nuclear Power Plants," in order for the NRC to approve the B&WOG's request.

D.5 References

[D-1] B&W Topical Report BAW-10027, "Once-Through Steam Generator Research and Development Report (Nonproprietary Version of BAW-10002)," April 1971.

[D-2] Draft Regulatory Guide 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes," dated August 1976.

[D-3] SECY-92-223, "Resolution of Deviations Identified During the Systematic Evaluation Program," USNRC, June 19, 1992.

Appendix E

Long Term Core Cooling Following a HL U-Bend Break

Note: Appendix E was added in Revision 2 of BAW-2374, however, no margin bars are shown.

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Table of Contents

List of Tables

List of Figures

Long Term Core Cooling Following a HL U-Bend Break

E.1 Introduction and Background

Loss of coolant accident (LOCA) analyses are undertaken to determine the adequacy of the emergency core cooling system (ECCS) to meet the five acceptance criteria prescribed in Title 10 Code of Federal Regulations (CFR) 50.46. Specifically,

1. The calculated peak cladding temperature (PCT) is less than 2200 F.
2. The maximum calculated local cladding oxidation is less than 17.0 percent.
3. The maximum amount of core-wide oxidation does not exceed 1.0 percent of the fuel cladding.
4. The cladding remains amenable to cooling.
5. Long-term cooling is established and maintained after the LOCA.

AREVA has developed an evaluation model (EM) based on the guidance of Appendix K to 10 CFR 50 to demonstrate that the B&W-designed plants can meet these acceptance criteria. This EM [E-7] focuses on minimizing the core cooling in the short term (i.e. during the blowdown and reflood phases) by examining a spectrum of break sizes and locations and applying a single failure of a loss of a train of ECCS. In general, a double-ended guillotine (DEG) break of the RCS piping in the cold leg pump discharge (CLPD) region presents the greatest challenge to the first four acceptance criteria during the short term. Hot leg breaks and cold leg pump suction (CLPS) breaks provide continuous core flow and are less limiting. In the longer term (post reflood), cooling is assured by preservation of the pumped ECCS flows through operator management of the ECCS equipment and decay heat removal equipment along with switching of the ECCS pump suction source from the borated water storage tank (BWST) to the sump. The CLPD break analyses set the core operating limits such that the first three criteria are satisfied in the event of a LOCA. The ECCS analyses and other structural analyses are used to demonstrate compliance with the fourth criteria on Coolable geometry. A variety of different operator actions are required and credited to ensure that long-term cooling is established and maintained until it is no longer needed.

In the late 1990s, a LOCA scenario was postulated that could challenge all of the acceptance criteria in the long term – a larger upper hot leg LOCA transient without the traditional single failure of a train of ECCS. Core cooling is assured early for all break sizes and locations in the hot leg, however, a new challenge was provided to the long-term core cooling. The full ECCS flow provides excess flow for core cooling and rapidly refills the reactor coolant system (RCS) to the elevation of the break, thus cooling all of the RCS piping and SG tubes. The thin steam generator (SG) tubes cool much faster than the thicker SG shell. Assuming a lower bound BWST temperature, the temperature differential between the thin SG tubes and the shell is quite large. Consequently, the SG tubes contract (shrink) at a faster rate but are resisted by the slower contraction of the thick shell creating thermally-induced tensile loads that could cause tubes with circumferential degradation to fail such that the primary fluid can flow through the broken tubes to the SG secondary.

A RELAP5/MOD2-B&W [E-2] analysis has been run to simulate the RCS response to a DEG LOCA in the hot leg U-bend (Appendix A). The results of this analysis provide an understanding of the timing of this event. Immediately after the break opens, the RCS pressure decreases and the initial inventory is expelled to the containment. The core flood tanks begin to discharge below an RCS pressure of 600 psig, and this flow in combination with the pumped ECCS injection rapidly refills the system. As the pumped injection continues, the injected liquid is heated by the core decay heat and stored energy of the RCS metal as it flows (1) through the core and up the hot leg to the RCS break and (2) backward through the broken loop SG tubes to the RCS pipe break. Between 300 and 400 seconds in the largest LOCAs, the RCS has refilled to the hot leg break location such that liquid begins spilling from the break. At approximately 800 seconds, the tube to shell differential temperature (TTS ΔT) has reached the maximum value. The tubes would be postulated to rupture as the maximum tube load is approached, but after the RCS refill time. The DEG upper hot leg break analysis from Appendix A was stopped at approximately 1000 seconds because the maximum TTS ΔT had been established. Beyond this time, the BWST liquid will eventually be exhausted and the pumped ECCS suction switched to the containment sump. Subsequently, the sump liquid is recirculated through the ECCS system (where it is cooled by one or two DH coolers) through the RCS (where it is heated by the core decay heat), out the break, and back to the sump. The primary-to-secondary leakage from the time of maximum TTS ΔT until the tube leakage is terminated depletes the available sump liquid inventory and degrades the available low pressure injection (LPI) pump net pump suction head (NPSH).

The severity of the transient may be exacerbated with a single failure that causes either a loss of a decay heat cooler or secondary side isolation. Loss of the decay heat cooler maximizes the sump liquid temperature during the sump recirculation phase of the event. The highest sump liquid temperatures in combination with the loss of liquid needed to completely fill the secondary side presents one challenge to the LPI pump NPSH. Alternately, a single failure of the secondary side to isolate can allow the additional liquid to exit to the environment outside of the containment. Continued loss of primary coolant means that the liquid level in the reactor building emergency sump is depleted. If the liquid loss is not stopped via operator action to isolate the flow path to the environment, there will not be sufficient liquid in the sump to maintain NPSH for the LPI pumps. The consequence of a loss of adequate NPSH is that the ECCS pumps may fail such that core cooling is jeopardized and eventually all five 50.46 acceptance criteria will be violated.

One of the overall objectives of the activities to support a revision to BAW-2374 is to evaluate the challenge to long-term core cooling from loss of RCS inventory through tubes that may rupture during the normal evolution of a hot leg LOCA. In particular, an evaluation of the amount of liquid lost to the secondary side is required. This will be accomplished by the following steps.

1. Determine the number of SG tubes that may be postulated to fail based on the loads following a hot leg (HL) U-bend break and the history degradation (i.e. as-found flaw distributions) from inspections of the SGs tubes.

2. Determine the rate and maximum amount of liquid lost through a postulated primary-to-secondary leak path.

3. Determine the containment sump liquid temperature.

4. Determine the effect of the liquid lost and the sump liquid temperature on the ECCS pump NPSH.

5. Evaluate the potential for a loss of secondary side isolation due to steam condensation water hammer loads that may challenge the steam and feedwater piping integrity.

Item 1 is discussed in Sections E.2. The amount of liquid lost to the secondary side and the containment sump liquid temperature is discussed in Section E.3. The effect on the NPSH is discussed in Section E.4, and the potential for steam condensation water hammer is addressed in Section E.5.

E.2 SG Tube Severs

The possibility that one or more steam generator tubes could fail (sever) due to the tensile loads generated by the large thermal gradients developed during the refill period of the hot leg U-bend break is evaluated in this subsection. Determining the potential number of failed SG tubes requires in-depth knowledge of the following information:

1. The maximum SG tube loads based on the LOCA thermal gradients,
2. The tube material properties (e.g. yield and ultimate strengths) and tube structural limits (i.e. allowable degradation vs load),
3. The expected SG tube flaw distributions, and
4. The probability of tube sever given the loads, tube strength, and expected tube flaw distributions.

The maximum projected SG tube loads for the LOCA event are determined in Section E.2.1. The calculations include consideration of the tubesheet flexure and provide the tubes loads as a function of tube radial position within the tubesheet. To show the effect that the TTS ΔT has on the tube loads, loads are determined for a wide range of assumed TTS ΔTs. In Section E.2.2, these tube load distributions are used with the tube material strengths and industry standard equations to establish the tube structural limits (allowable flaw size). The structural limits are also provided as a function of TTS ΔT and tube radial position within the tubesheet. The expected SG flaw distribution is developed in Section E.2.3 and is based on the previous tube inspection data from all the OTSGs, both those in service and those that have been replaced. The projected tube flaw distributions are conservatively used with a "bounding" tube axial load and industry standard equations to calculate the probability of a given the number of severed tubes in Section E.2.4.

E.2.1 SG Tube Loads

The maximum tube loads in the OTSG associated with the LOCA event are the axial loads resulting from the large temperature differences that can develop between the tubes and steam generator shell. Appendix A provides details of thermal hydraulic analyses and evaluations used to determine the RCS system responses for a number of different LOCA scenarios (break locations and sizes). The analysis is based on transient initiation from full power conditions without credit for main feedwater (MFW) liquid flashing to reduce the temperature difference and provides conservative TTS ΔTs for a number of transient conditions. A review of Appendix A shows the maximum projected temperature difference between the tube and shell is 375 F and occurs for the upper hot leg U-bend LOCA occurring from full power initial conditions.

The tube loads associated with the large ΔT are determined using the results from a previous detailed thermal and structural analysis of a similar LOCA event, a break in the attached pressurizer surge line. The detailed analysis of the surge line LOCA covered all the operating OTSG configurations and included cases for both 0 and 25% tube plugging geometries. It also took into account the relative stiffness of the tube bundle, shell, tubesheets, and upper and lower heads and as a result provides the load distribution across the bundle associated with tubesheet flexure (bowing). A review of the surge line break and hot leg U-bend break thermal hydraulic response shows the timing is different RCS responses are similar in that they both drain the RCS and then refill it to the break location. The main difference between the two events is that the ECCS completely refills the primary tubes for the hot leg break and continuously flows through them to exit the break. The location of the surge line limits the tube refill to the elevation of the surge line and doesn't allow ECCS to flow through the tubes above the break elevation. The U-bend break provides additional tube cooling that creates a larger TTS ΔT. The tube loads for the LBLOCA are determined by increasing the pressurizer surge line LOCA loads by the ratio of LBLOCA ΔT to surge line LOCA ΔT. The maximum tube loads for the surge line break occur for the raised-loop design with zero percent SG tube plugging with a maximum TTS ΔT of 219F. The LBLOCA loads associated with the maximum temperature difference of 375F, as well as other smaller differences, are evaluated and are provided in Figure E-1. The figure provides the tube load distributions for transients ranging from the 219F ΔT surge line LOCA transient to the bounding 375F ΔT for the LBLOCA event.

The tube load curves shown in Figure E-1 are based on a purely elastic analysis with no consideration of potential yielding of the tube. The horizontal dashed "upper bound" line in the figure represents the limiting load that the tube can experience based on the yield strength of the tube. The overall displacement (potential strain) from the tube-to-shell temperature differential is not sufficient to drive the tube loads beyond the yield strength of the tube. In fact, the displacements are such that the maximum tube load from an actual load displacement (stress-strain) curve would not reach the 0.2% yield offset load. It is therefore concluded that the maximum thermally induced load for the OTSG tube is limited by the yield strength of the material, or ~3300 lbs (average strength at 150 F) for the tubes in question. Although Figure E-1 provides a distribution of tube load versus tubesheet radius, the upper bound yield load is conservatively used for all tubes in determining the potential number of severed tubes. The distribution of tube loads is provided for information and could be used if necessary to help limit the number of projected severed tubes associated with this postulated hot leg LOCA.

E.2.2 Hot Leg U-bend LOCA Tube Structural Limits

As discussed previously, the critical loading from the LOCA event is the tube axial load associated with the large TTS ΔT. Experience shows the only tube flaws that could produce a tube severe from the axial loads are those with circumferential extent. Circumferential cracks or volumetric flaws fall into this category. Therefore, only circumferential degradation need be considered in the assessment of tube structural integrity for the postulated hot leg U-bend LOCA event. The assessment will consider circumferential degradation located within the tubesheet and in the free span.

The assessment of hot leg U-bend LOCA tube integrity begins by determining the allowable circumferential degradation (flaw size) as a function of tube axial load. Recently updated industry standard equations for the rupture of a tube containing circumferential degradation are used. These equations are currently being incorporated into a revision of the EPRI Flaw Handbook [E-4]. Equations are available for degradation located in the free span of a tube and also in a location with restrained bending, like that within the tubesheet. Both equations are applicable to degradation located on the tube outer diameter (OD). An additional factor to account for the presence of pressure on the face of a flaw located on the tube inner diameter (ID) is also provided in the Flaw Handbook. However, since the pressure associated with the hot leg U-bend LOCA axial load is negligible (< 50 psi), no adjustment is needed and the equations are suitable for both OD and ID flaws. Using the revised Flaw Handbook equations and OTSG tube geometry and material properties, the allowable tube axial loads as a function of percent degraded area (PDA) for circumferential degradation are determined for both the free span flawed tubes and those with restrained bending (e.g. within the upper or lower tube sheets). The results of the calculations are provided in Figure E-2. The limiting of the two equations is shown and provides the limiting allowable axial load for free span circumferential degradation in a tube under axial loading.

To provide a general sense of the effect of TTS ΔT and tube radial position within the tube bundle on the structural integrity of OTSG tubes, the allowable circumferential degradation (flaw size) as a function of these parameters is also determined. The projected hot leg U-bend LOCA tube loads as a function of tubesheet radius and various magnitudes of TTS ΔT from Section E.2.1 are used with the allowable degradation versus axial load curves of Figure E-2 to determine the hot leg U-bend LOCA allowable circumferential flaw size as function of tubesheet radius and ΔT. The results for degradation in the free span are provided in Figure E-3. The results for degradation in a tube with restrained bending are shown in Figure E-4. These figures can be used to characterize as-found flaw sizes that could sever as a function of tubesheet radius and TTS temperature difference for future SG tube leakage assessments. However, the calculation of potential tube severs contained in this topical does not take credit for the axial load distribution across the bundle. It is conservatively based on the assumption that all tubes are loaded to the upper bound axial load associated with the yield strength of the tube material.

E.2.3 Potential Primary-to-Secondary Leak Paths

Axial loads are the only significant loads of interest during a hot leg U-bend LOCA event. Since axial degradation is not significantly influenced by axial loads, only circumferential cracking and volumetric degradation needs to be considered. In terms of axial strength, the circumferential extent and depth of degradation are the parameters of interest for volumetric flaws as is the case for circumferential cracking. The limiting case for the axial strength of volumetric flaws is a circumferential crack of the same circumferential extent and depth.

Figure E-5 shows a sketch of an OTSG tube. Circumferential cracking has been observed at the following locations:

- Upper and Lower Tube Ends
- Upper Tubesheet Roll Transitions
- Upper and Lower Tubesheet Secondary Faces
- Upper Tubesheet Crevices
- Free span Dents and Dings

Volumetric intergranular attack (IGA) has been observed in upper and lower tubesheet crevices and in the free span. There are several instances of chemistry transients leading to volumetric IGA. Although these tubes are plugged when degradation is detected (otherwise known as plug-on-detection repair), volumetric OD IGA continues to appear.

The leakage path for circumferential cracking at tube ends is the tube-to-tubesheet interface at the rolled expansion portion of the tube. Even considering maximum tube dilation effects this leakage area is less than 0.002 in^2. For degradation within tubesheet crevices the limiting leakage path is the gap between the unexpanded tube and the tubesheet. The width of this annular gap is 0.0075 inches leading to a maximum leakage area of 0.014 in^2. These leakage areas are overwhelmed by the leakage area of a free span tube sever. The ID area of a tube is 0.24 in^2. For a DEG break, the leakage area is then 0.48 in^2. From the perspective of large leak rates, only free span tube severs are of interest, because the leakage from one free span tube sever is equivalent in area to roughly 34 tube severs within the crevice annular gap or approximately 240 tube severs between the end of the tube and the roll expanded region of the tube. The hot leg U-bend LOCA leakage contribution from tube end cracks (TECs) and tubesheet crevice degradation is a small fraction of the leakage from a free span tube sever.

The maximum hot leg U-bend LOCA axial load leads to a tube elongation of about one inch. Therefore, a tube that severs within one inch of a tubesheet secondary face would contract and exist outside the confines of the tubesheet and become a free span leakage path. In considering the degradation that may lead to a free span tube sever; the free span region is taken conservatively as the region three inches above the upper tubesheet secondary face to three inches below the lower tubesheet secondary face.

When considering future leakage assessments from as-found tube flaws against the flows (or effective leakage areas) used in demonstrating compliance with 10 CFR 50.46, both free span and tube crevice cracks will be included. However, it is recognized that the leakage is dominated by the free span flaws that could break during a postulated hot leg LOCA.

E.2.4 Probability of SG Tube Failure

The most detailed and sophisticated approach to tube integrity evaluations is a full Monte Carlo simulation of the processes of degradation initiation, growth, and nondestructive examination (NDE) inspection over multiple cycles of steam generator operation. In this manner both detected and undetected populations of degradation are tracked and can be evaluated for tube rupture and leakage. Years of experience with this technique, benchmarked against actual service experience leads to the following important and useful conclusions for a plug-on-detection repair scenario:

- The distribution of end-of-cycle (EOC) degradation lengths after multiple cycles of operation becomes relatively stable.
- The distribution of detected depths of degradation becomes relatively stable and approximates the shape of the probability of detection curve for the applied eddy current inspection technique.
- The probability of an undetected degradation site leading to tube rupture is extremely low and can be neglected.

These observations, supported by multi-cycle Monte Carlo calculations of actual plant experience, provide the basis for a relatively simple method of calculating the probability of tube severs under large break LOCA loads. These results can then be used to help define a reasonable number of tube severs to be used in the analyses to demonstrate adequate NPSH during the long term core cooling phase of the LOCA. The number of severed tubes selected will also become a new consequential SGTR leakage area basis for assessing if future as-found tube flaws remain within the acceptable bounds established by the LOCA and NPSH analyses in Sections E.3 and E.4.

The future distribution of EOC degradation lengths was determined from past observations. Figure E-6 shows a plot of degradation lengths at Oconee Unit 1 for the last two outages prior to replacement. The solid line is a natural log (ln) normal fit to the bounding distribution. It is a good representation of the worst case distribution that can be expected in a steam generator which has operated for about 22 effective full power years (EFPY). The only operating original OTSGs are Davis Besse, Crystal River Unit 3 and TMI. Of these, TMI is the lead plant at 19 EFPY with SG replacement scheduled in 2009. A ln normal length distribution with a mean (ln values) of -1.1436 and a standard deviation of 0.2436 is a good bounding distribution of degradation lengths for these plants at their projected end of life after two or three more operating cycles.

The future distribution of degradation depths can be determined from past observations and checked against the eddy current probability of detection (POD) curve. Distributions of NDE measured maximum depths of volumetric degradation at Crystal River Unit 3, Davis Besse and Oconee Unit 1 for the last one or two inspections are plotted in Figure E-7. NDE sizing uncertainty distorts the tails of these distributions, skewing the lower tail to smaller depths and the upper tail to larger depths. A review of the data for the four largest depths shows that depths have been overestimated. In three cases this was due to low eddy current signal amplitude. In the remaining case the presence of a dent distorted the phase angle depth measurement. A log logistic curve was fitted to the trend band of the depth distribution using the mid point of the band and the average cumulative distribution at about 60% through wall (TW). Since depth distributions become stable after multiple cycles of operation with a plug-on-detection repair scenario and the same inspection technique and calling criteria, the fitted distribution can be used to represent the depth distribution expected in the future.

Use of the flaw distributions from steam generators that have been replaced is used in an attempt to bound the future flaw distribution. Replacement of any steam generator should occur prior to when the number and size of flaw distributions exceeds that for the other replaced steam generators. Although it is not expected, it is natural to expect that if the number of degradation sites increase in the future and more selections from this depth distribution are made, the number of instances of degradation sites with large depths will increase. This potential is addressed by including a future commitment to check the as-found flaws and ensure that the number and size would not result in a projected primary-to-secondary leakage area greater than that used in the thermal-hydraulics analyses discussed in Section E.3.

As noted earlier, the detected depth distribution becomes about equal to the POD curve after multiple cycles of operation with a plug-on-detection repair scenario and the same inspection technique and calling criteria. Figure E-8 shows two POD curves of interest. The dotted line is a POD curve for volumetric IGA in the upper tubesheet crevice at ANO based on pulled tube data. It is slightly more adverse than the detected distribution curve at large degradation depths. This is the region that dominates calculations of the probability of tube sever. Upper tubesheet degradation in the ANO-1 OTSGs (which have since been replaced with EOTSGs) is believed to be due to sulfur incursions on the secondary side in the early years of steam generator operation. Tube pulls show that this type of degradation can lead to instances of deep degradation with short circumferential extents. This morphology would lower POD values at large depths. The dashed line is more representative of the general free span degradation at issue for large hot leg U-bend LOCA leakage. This POD curve is based on an extensive study of 85 pulled tube degradation sites and includes multiple analysts to include analyst uncertainty. The detected distribution curve is selected as the best-estimate distribution. The two POD curves are considered as reasonable bounds to the upper tails of the distribution of EOC maximum depths. Circumferential cracking is detected with the Plus Point eddy current probe. The POD curve applicable to this type of degradation is bounded by the curve of Figure E-8. Hence, the same distribution of maximum depths can be applied to both volumetric IGA and circumferential cracking.

Trending of the number of past indications versus operating time can be used to develop projections for the number of indications at future times of interest. Since large break LOCA axial loads depend on radial position within the tube bundle, the radial distribution of degradations sites must be considered. Since large break LOCA axial loads are highest at the periphery of the bundle, degraded tubes in the periphery dominate calculations of the probability of tube sever. The radial distributions of free span volumetric IGA and circumferential cracking were evaluated based on inspection data of current OTSGs and OTSGs that have already been replaced. Use of data from replaced OTSGs provides a mechanism for looking at increased degradation as the remaining OTSGs age.

Existing inspection data of replaced, as well as existing OTSGs, reveal a maximum of 40 to 60 indications with volumetric extent as shown by the number of data points in Figures E-6 and E-7. There was however, no clear trend of radial distribution of degradation from one steam generator to the next. In some cases degradation is located primarily in the center of the bundle, while in others most degradation is in the periphery. Other steam generators approach a more or less uniform radial distribution. In the last two operating cycles for the Oconee Unit 1 OTSGs that have since been replaced, the degradation was near the periphery. In the Oconee Unit 2 OTSG A, which has also been replaced, the indications were more uniformly distributed. Of the original steam generators still in operation at 3 plants, Crystal River Unit 3 had too few indications of free span degradation in the past two inspections to indicate a trend of radial distribution. Davis Besse had a large number of indications near the center of the bundle. Based on this inspection data, a reasonable to conservative choice for an end of life projection is to place half of the total number of projected indications at the periphery. Therefore based on the total number of indications, the worst case projection is thus 20 to 30 degradation sites at the highest load location with a length and depth for each picked from the distributions illustrated in Figures E-6 and E-7.

It is noted that TMI SG A has a large number of free span volumetric indications. These indications originated from water chemistry effects during the layup period in 1979 and 1980 and are relatively small and stable. TMI requested and received permission from the NRC to use an alternate repair criterion to leave tubes with this degradation in service without repair. The maximum circumferential extent of 0.33 inches and maximum depth of less than 40% TW for any of these indications results in a percent degraded area of less than 7 percent. Figure E-2 shows that a flaw with this area reduction would require a load much greater than the upper bound tube tensile load to create a tube sever. Since these flaws are not candidates for tube sever, the 20 to 30 peripheral degradation sites selected from the much more adverse length and depth distributions of Figures E-6 and E-7 remains a bounding worst case projection for calculating the probability of tube sever.

With the above as input, the probability of a tube sever can be calculated per detected degradation site. For a single degradation site, maximum depth and circumferential extent is selected from the appropriate EOC distributions. Tensile properties (yield and ultimate strength) are assigned from the known distribution that is characteristic of the

OTSG fleet. The strength of the degraded tube is then compared to the hot leg U-bend LOCA load of interest. This constitutes one Monte Carlo trial. After many trials, the number of tube severs divided by the number of trials is the best estimate of the probability of a tube sever on a per indication basis. Given this probability and the number of degradation sites of interest, the binomial distribution can be used to determine the probability of 0,1,2…etc tube severs for a hot leg U-bend LOCA event.

Figure E-9 shows the calculated probability of tube sever per indication (degradation site) versus axial load. The probability of a tuber sever per indication rapidly decreases as the applied load decreases. Thus considering all projected peripheral degradation sites to be located at the highest axial load is conservative. The nominal estimate EOC end of life depth distribution leads to a probability of tube sever per indication of 1.41e-3. This value is increased to 1.61e-3 if the depth distribution is approximated by the POD curve for upper tubesheet crevice volumetric IGA at ANO. It is decreased to 1.20e-3 if the more generally applicable free span volumetric IDA POD curve is used as the EOC depth distribution.

Since more than one degradation site is expected in the worst case generator at end of life, the binomial distribution must be used to determine the probability of 0,1,2,...X tube severs for a hot leg U-bend LOCA event at this worst point of operating history. If the probability of a tube sever per indication is p, the probability of exactly X tube severs considering N indications, $P_x(N)$ is given by:

$$P_x(N) = \frac{N!}{X! \bullet (N-X)!} \bullet p^X \bullet (1-p)^{(N-X)}$$

Figure E-10 shows a plot of probability of occurrence versus number of tube severs for various number of degradation sites at end of life using an axial load of 3300 lbs. Prior inspection results suggest that roughly 30 free span degradation sites may be found in the periphery tubes at end of life. When 30 flaws are postulated, the nominal probability of no tubes severs is 0.95864. The probability of one tube sever is 0.04052. The probability of more than one tube sever is then 1-0.95864-0.04052 = 0.00084. Clearly a hot leg U-bend LOCA is an event where only a single tube sever could be expected.

A single tube sever event is still the case for the upper estimate of 1.61e-3 for the probability of tube sever per indication at 3300 lbs. With this per indication probability, the probability of no tube severs is 0.95281, one tube sever is 0.046095 and more than one tube sever is 1.09e-3. Figure E-11 is a repeat of Figure E-10 using the upper estimate of the probability of tube sever per indication. The single tube sever nature of a hot leg U-bend LOCA event is evident even for relatively large numbers of degradation sites at end of life. As a worst case upper bound at very low probability a few tube severs might be considered in evaluating leakage consequences to establish some margin to address flaws that may be found in the future.

Based on the conservative upper bound estimate of tube failure from Figure E-11, failure of four tubes is less than 10^{-6} for up to 40 circumferential indications in the upper bound tensile loading region. Even if the number of indications is quadrupled to 160, the probability of four tubes failing is roughly 10^{-4}. Based on either of these low probabilities, consideration of more than four failed tubes is overly conservative and therefore should not be considered in the NPSH analyses that begin with an event that has an estimated frequency of 8×10^{-7}/year. If the number of high load indications increased in the future to a total of 160, then roughly 1 percent of the total number tubes in the steam generator (~15,000) needs to be plugged during the outage. It is also recognized that the tube plugging for each cycle is trended and used in predictions for establishing the life of the SG. If this number of tubes is plugged each cycle, those trends would accelerate the time table to replace the generator.

E.3 Loss of ECCS Inventory

A RELAP5/MOD2-B&W system analysis was preformed to determine the amount of liquid lost through a postulated primary-to-secondary leak path. The model postulated a break in the hot leg piping and a conservatively high number of SG tube failures based on the previous discussion of the probability of tube sever. A detailed SG and steam line geometry was included so that an estimate of the rate of liquid lost and the total volume of liquid lost could be determined. A GOTHIC containment analysis was performed to determine the containment pressure and sump liquid temperature. The containment pressure response was used as a boundary condition in the RELAP5/MOD2-B&W system analysis to determine the leak rate. A conservatively high leakage rate is obtained when a "maximum" containment pressure is used from the HL U-bend LOCA that could result in consequential steam generator tube ruptures (SGTRs). This maximum pressure is not the maximum building pressure used to establish equipment qualification or the building design. Instead, it is a LOCA containment pressure analysis with the input skewed to produce a maximum pressure in lieu of the minimum pressure typically used for analyses that establish the LOCA linear heat rate (LHR) limits. The sump liquid temperature response is available for use in the NPSH calculation if necessary.

E.3.1 Analysis Inputs

In demonstrating compliance with 10 CFR 50.46 long term cooling (LTC) following a hot leg LOCA, it is difficult to establish a single, bounding analysis, because many of the parameters influence portions of the calculations in opposite directions. For example, the BWST liquid temperature has multiple effects on the analysis. As the BWST liquid temperature decreases, the tube stresses increase as does the susceptibility of tube ruptures. The colder BWST liquid results in colder sump liquid temperature, which beneficially increases the LPI pump NPSH. At the time that the SG tubes fail, the RCS liquid loss through the failed tubes to the secondary side of the SG is controlled in part by the pressure difference between containment and the atmosphere. The colder BWST liquid decreases the containment pressure and reduces the pressure differential driving flow through the broken steam generator tubes. A lower containment pressure means less liquid lost and increased NPSH. Conversely, a higher BWST liquid temperature decreases the susceptibility of tube rupture, reduces the LPI pump NPSH margin during sump recirculation with elevated sump liquid temperatures, and also increases the containment pressure leading to higher pressure differential to increase the primary-to-secondary leakage rate per broken tube.

Other key parameters influence the tube loads and containment pressure in similar, contradictory ways. Providing a bounding analysis for each of the key portion of the LTC calculation (i.e. tube load, maximum containment pressure, maximum RCS pressure, lowest SG secondary side level and pressure, minimum temperatures for water-hammer scenarios, etc.) by skewing parameters in opposite directions will provide unrealistic and unnecessary challenges to the LTC evaluation. Adequate assurance of LTC is provided by using nominal parameter ranges for variables that can skew the results in different directions (such as BWST temperature, core power, decay heat level, etc) and generally bounding other inputs (such as minimum BWST liquid volume, initial containment pressure and temperature, break size, number of ruptured tubes, etc.) in the analysis to provide overall conservatism in the evaluation.

As an example, analyses to determine the probability of tube sever have been completed based on the maximum tube loads predicted by lower bound BWST temperatures to determine that the probability to sever more than one tube was extremely low based on all plant as-found SG tube conditions (Sections E.2). These results were based on LOCA conditions that did not credit additional secondary side inventory from the MFW flashing that may augment the SG shell cooling and delay the SG tube temperature decrease. These conclusions remain valid and independent of initial core power or decay heat level. Nonetheless, the RELAP5/MOD2-B&W analyses to determine the primary-to-secondary leak rates considered four severed tubes to conservatively bound the leakage rates and provide a high limit for assessing future tube degradation while preserving LTC in accordance with 50.46. The RCS break size and containment inputs used in these analyses were also skewed to values that would independently maximize the RCS leakage through the four free span ruptured tubes. Using these conservative inputs provides latitude to select a more reasonable set of analysis inputs for other parameters that will not unduly constrain the operator actions that may be required to preserve LTC. That is, assumptions used to determine the maximum SG tube loads do not necessarily have to be consistent with the assumptions used to determine the sump NPSH. Each portion of the analysis can be done independently with its own unique combination of best-estimate and conservative assumptions to address the competing effects described in the preceding discussions.

The hot leg break simulation for the primary-to-secondary leak rate calculations was completed with several significant conservatisms. The following list gives the conservatisms that were included in this analysis.

1. Based on the operating history of all the OTSGs (even the ones replaced with new SGs) and the current procedures to repair on detection, a probability analysis determined that the likelihood of a single tube severing in the free span (i.e. double-ended tube failure outside of the SG tubesheet) is approximately four percent (Section E.2.4) based on 30 indications. The probability of an additional tube severing is approximately two orders of magnitude less. Each subsequent tube sever becomes less and less likely. Given this information, selection of a large number of tube severs is not necessary to bound any expected future as-found flaw distributions. Postulating more tube severs reduces the overall likelihood that it could actually occur; however, postulating substantial numbers of failed tubes results in additional leakage that will considerably shorten the time the operators have to isolate the secondary side and stop the loss of the liquid that supplies the ECCS suction during the long-term core cooling phase. When many tube failures are postulated the isolation time needed to preserve pump NPSH and the 50.46 acceptance criteria may require potential undesired EOP sequence revisions that could displace higher priority operator actions needed to address more likely scenarios. With two competing

effects, a compromise must be struck that reasonably bounds the possible number of tube severs, but does not result in undesired procedural changes to address the inventory loss. Therefore, the analysis assumed a primary-to-secondary leak area equivalent to four tubes. Using an upper bound estimate, the probability that more than four tubes will sever is less than 10^{-6} for up to 40 flaw indications (Figure E-11). Using nominal values, this probability decreases even more (Figure E-10). When these are combined with the probability of a HL LOCA in the candy cane of $8x10^{-7}$/year (from Section 3.4.3.1), the probability that four tubes would rupture is in the range of 10^{-12} to 10^{-13}. Therefore, assuming four tube failures should provide ample margin to bound the leakage from future operation and possible as-found tube degradations in OTSGs or their replacements. The primary-to-secondary leak area through these four severed tubes was determined to be 0.007 ft^2 from each side for all SGs under consideration.

2. It has been established that a rupture of the hot leg piping in the vicinity of the hot leg U-bend will produce the most limiting SG tube loads and maximize the probability of a SG tube sever (Appendix A). The break location will completely refill the primary SG tubes region and provide a continuous liquid flow through the tubes such that the tubes temperature can be cooled to near the ECCS liquid temperature. The pressure that drives liquid through the tube rupture is the difference between the RCS pressure at the tube failure and the SG secondary side pressure. The RCS pressure at the top of the hot leg pipe will stabilize in the longer term near the containment pressure plus any pressure drop needed to discharge the pumped ECCS through the break. While a double-ended break will produce the earliest SG tube rupture, the pressure drop through the break is minimized, because the RCS pressure approaches the containment pressure. Smaller break sizes can also produce SG TTS ΔTs that are in excess of the SG tube load produced by the limiting attached pipe break or the MSLB tube loads that do not exceed the SG tube yield strength such that SG tubes are not predicted to fail. These breaks will not depressurize the RCS as quickly as the full area DEG break. A slower RCS depressurization reduces the ECCS flows, which delays SG tube refill time allowing additional time for the SG shell to cool down.

However, the reduced break size causes the RCS pressure during the longer term phase of the event to remain above containment pressure by a pressure differential needed to pass the ECCS out of the smaller break size. The net pressure differential available to drive liquid through the tube rupture is then the RCS overpressure in addition to the elevation difference between the liquid level in the RCS and the liquid level in the SG secondary. Consequently, the SGTR differential pressure is larger and more liquid is lost through the same size SG tube failure for a smaller RCS break.

From the previous discussion it is obvious that there are competing effects in selecting the RCS break area. If four tubes are postulated to sever regardless of the RCS break area, the conservative choice is to use a smaller break size in the range of 0.5 to 1.0 ft^2. Break sizes smaller than this result in a higher RCS pressure, however, the higher pressure reduces the pumped ECCS injection such that the TTS ΔTs will be less. The lower temperature difference reduces the tube loads, potentially below the SG tube yield strength (see Appendix A and Section E-2), and greatly diminishes the likelihood of multiple SG tube ruptures. Therefore, using the RCS pressure response from a 0.75 ft^2 hot leg U-bend break occurring at nominal full power conditions is a reasonable, yet conservative choice that provides considerable margin for future as-found flaw leakage evaluation, but is not expected to seriously impact the EOP action times.

3. The initial steady-state core power and decay heat level play a variety of different roles for this transient. Low steady-state power levels have the lowest SG levels and provide less energy to heat up the ECCS refilling the RCS and flowing backward through the SG tubes, thereby maximizing the SG TTS ΔT. The low liquid level also maximizes the volume of primary liquid that may be lost and increases the rate of loss, because the secondary side elevation head is lower. However, low power levels decrease the long-term containment pressure and lower the sump liquid temperature such that the RCS pressure driving the primary-to-secondary leakage rate decreases and the NPSH margin increases.

While the tube load is higher at low power, the probability of sever is not appreciably changed at low power, because the tubes exceed the yield limit and elongate to relieve the load. The maximum elongation from an extreme case with effectively no core power is not sufficient to appreciably increase the probability of tube rupture. Therefore, the number of SG tube ruptures postulated is relatively independent of core power. Since the number of tubes severed is not a function of power, a higher power is selected because it is conservative from an NPSH and containment long-term containment pressure perspective. Therefore, the analyses were performed with the Davis-Besse rated power of 2772 MWt using a decay heat multiplier of 1.0 on the ANS 1971 infinite operation fission product decay with an additive heavy isotopes contribution. The ANS 1971 decay heat standard is conservative compared to more recent predictions of core decay heat. Using a 1.0 multiplier on this conservative decay heat will produce a high, yet reasonable, decay heat for this analysis.

4. Other key conservatisms are included in the parameters or boundary conditions used in the analyses. Table E-1 gives a listing of key inputs.

E.3.2 Containment Response

The determination of the primary-to-secondary leakage requires an appropriate containment pressure that represents a maximum value that bounds the B&W-designed plants. The sump NPSH calculation is based in part on the containment sump liquid temperature. The code selected to determine these parameters following a hot leg LOCA that results in SG TTS ΔT sufficient to severe SG tubes is GOTHIC (Generation of Thermal-Hydraulic Information for Containment, [E-1]. GOTHIC is a general purpose thermal-hydraulics computer program for design, licensing, safety, and operating analysis of nuclear power plant containments and containment sub-compartment and other confined buildings. A GOTHIC model that represents a composite B&W plant was developed. This model consisted of three control volumes – the containment building, an RCS, and a small volume for the decay heat coolers. The main containment modeled the free volume and included major passive heat sinks. Provisions for mass and energy

(M&E) release from the RCS during blowdown, refill, and sump recirculation were included. In particular, the M&E from the RELAP5/MOD2-B&W analysis in Appendix A was used. The pumped ECCS injection was simulated to take suction from the BWST and the containment sump once the BWST was depleted. Core decay heat, RCS metal stored energy, and the decay heat coolers were considered. Containment spray and building coolers were modeled. The inputs and modeling choices considered the guidance provided in Reference [E-3] for generating a conservatively high containment pressure. This composite plant GOTHIC model is capable of evaluating a reasonable, upper limit on both the containment pressure and sump liquid temperature for any B&W plant during the hot leg LOCA transient that would generate sufficient TTS ΔT to sever SG tubes.

After the time of sump switchover, the suction source for the ECCS and building sprays will switch from the BWST to the containment sump. The ECCS will be cooled by the decay heat (DH) cooler(s) before it is returned to the RCS. Some of the ECCS liquid that passes through the core absorbs the core decay heat and any residual heat of the RV and hot leg metal before exiting the break and spilling back into the sump. The remaining ECCS liquid flows backward through the pumps and steam generators absorbing residual heat from them and the cold leg metal before exiting the break. While the temperature at the exit of the DH coolers is higher than the BWST temperature, it is still an effective means for removing this heat. A failure of one DH cooler will significantly decrease the heat removal capacity of the ECCS and delay the cooldown of the sump liquid temperature. Therefore, two containment analyses were examined. Each case considered two building spray pumps, an initial containment pressure of +3 psig, an initial containment temperature of 130 F, a BWST temperature of 90 F, and an ultimate heat sink temperature of 95 F. The only variation between the cases was the number of DH coolers. The first case considered two DH coolers. The second case considered one DH cooler (i.e. a failure of one DH cooler). The containment pressure and sump liquid temperature of the two cases are compared in Figures E-12 and E-13, respectively.

After the time of sump switchover, the building spray flow does not pass through the DH coolers. Consequently, the spray liquid temperature is increased from the BWST temperature (90 F) prior to sump switchover to the sump liquid temperature (~160 to 200 F). The sprays play a significant role in depressurizing the containment after the end of RCS blowdown, primarily due to the low temperature liquid that is sprayed into the upper containment. The increase in the spray source temperature reduces their cooling effectiveness and allows the containment pressure to increase slightly because of the higher temperature in the building vapor space. In the longer term, the heat removal from the building fan coolers and DH coolers match and exceed the core heat sources and the sump liquid temperature begins to decrease. The building spray recirculation of the sump liquid allows the DH cooler(s) to effectively reduce the containment pressure. With the failure of a DH cooler, the decay heat matchup time is delayed and sump liquid temperature increases for a time (see below). The higher sump temperature liquid recirculates into the atmosphere by the building sprays. Consequently, the containment pressure for the case with a failed DH cooler is approximately 4 psi higher at the end of the run than if both coolers were in operation.

The heat rejection capability of the fan cooler(s) and two DH coolers is sufficient to remove core decay heat at the time of sump switchover. With both DH coolers in operation, the sump liquid temperature continues to decrease. The loss of a DH cooler effectively reduces the decay heat rejection by half. The liquid temperature at the exit of the active cooler does not change. However, the liquid temperature at the exit of the failed cooler is the same as the sump liquid temperature. Consequently, the average ECCS liquid temperature increases, which reduces the heat removal capability of the ECCS and the sump liquid temperature increases. As the core decay heat decreases, the single DH cooler is sufficient to remove this energy and the sump liquid temperature begins to decrease. However, at the end of the run, the sump liquid temperature for the case with a single DH cooler is approximately 25 F higher than for the cases with the two DH coolers.

For the primary-to-secondary leakage calculation, a higher containment pressure is conservative, because it maximizes the leakage rate. For the sump NPSH calculation, a higher liquid sump temperature is conservative, because it reduces the subcooling and the available head. On both accounts, the case with only one DH cooler provides conservative results. Therefore, the containment pressure and sump liquid temperature as a function of time for this case were used to evaluate the primary-to-secondary leak rate and the sump NPSH following a LOCA that produces a SG tube failure or failures.

E.3.3 Primary-to-Secondary Leakage

The calculation of the primary-to-secondary leakage was determined using RELAP5/MOD2-B&W [E-2]. The primary-to-secondary side leak rate can be used to determine the ECCS inventory lost through the severed SG tubes and the time it takes to fill the SG and the main steam lines.

The model developed in Appendix A to determine the SG tube loads was used as the basis for this analysis. The following modifications were made to the model for this task. The initial and boundary conditions used to maximize the tube loads were changed to match those identified in Section E.4.1 to maximize the tube leakage rates. The containment pressure boundary condition was set to that determined by GOTHIC as described in Section E.3.2 with inputs that skewed the pressure to maximum values. A detailed steam line was added to the model for an accurate prediction of the inventory lost to the secondary side. In order to bound all of the B&W plants, the CR-3 steam line was modeled. It has the lowest steam line spillover elevation and provides the smallest liquid elevation head on the SG secondary side to maximize the pressure differential and the rate of liquid lost from the RCS. Further, a primary-to-secondary leak path was modeled to open near the time of maximum TTS temperature difference. The earliest time for the maximum temperature difference is for a DEG break and this occurs slightly after 10 minutes. Once the SGTR occurs, the calculations showed that the secondary side tube bundle can be refilled to the top of the shroud within 57 minutes. Therefore, the earliest time that the liquid can begin to flow into the steam line is 67 minutes from the onset of the transient. Isolation of the steam line prior to this time limits the inventory loss to the total volume of the secondary side up to the isolation points. If the steam line is isolated after this time, any loss through an unisolated path needs to be considered in the total inventory lost from the sump.

The composite RELAP5/MOD2-B&W LOCA and containment model that represented all the B&W-designed plants participating in the program produced conservative primary-to-secondary leakage rates summarized in Table E-3. These leakage rates are only applied to the steam generator in the broken loop, because the intact loop steam generator will not have sufficient tube stresses to potentially cause consequential tube ruptures. The time-dependent leakage rates will be used as a maximum primary-to-secondary leakage criterion for as-found tube flaws based on the Condition Monitoring Program that includes this supplemental hot leg pipe LBLOCA accident leakage assessment as directed by the Licensing Commitments or plant Technical Specifications. The assessments will assure that the cumulative plant-specific leakage rate is less than the criterion to validate that the BAW-2374 analyses remain bounding.

This leakage assessment may be performed in a variety of ways that range from conservative generic approaches all the way to detailed plant-specific assessments based on the methods of analyses contained in the BAW-2374 analyses. Additional detail on these approaches is provided in Appendix G. The simplest evaluation uses the conservative effective leakage flow area of 0.014 ft^2 (2 * 0.007 ft^2) in the generic analyses as a criterion for cumulative effective leakage area from the as-found flawed tubes. The flawed tube integrity could be based on either applying the maximum tube loads based on the yield limit for the tubes, or alternatively the tube loads applied based on the radial location within the steam generator. Effective leakage areas can be calculated based on summing broken area of the free span tube flaws (each limited to twice the area of the tube cross-sectional area) with any flaw areas from tubes inside the upper or lower tube sheets. The leakage area of the flaws within the tube sheet is limited to the smaller of the flaw open area or the minimum annular flow gap along the axial flow path between the flaw and the secondary side flow bundle region. A similar approach is used for leakage around sleeves that could span a flaw that could have failed under the LBLOCA tube thermal load.

If the conservative leakage methods are too restrictive, they could be refined and conservatisms removed from the generic evaluation contained in this Topical Report. The total leakage flow rate from the refined plant-specific analysis method should be less than the cumulative integrated leakage flows given in Table E-3. These refinements could be based on a plant-specific analysis with consistent inputs for the reactor building containment volume or the plant specific main steam line geometry using the BAW-2374 analysis methods. With this plant-specific method of analysis, the actual radial tube location can be used to limit the loads and the axial elevations of the flaws can be used in the plant-specific analysis to lower the leakage rates that are based on revised differential pressures across the open area of the tube flaws. The cumulative SGTR leakage rate from the plant-specific analysis can be integrated for comparison against the integrated time-dependent leakage rates given from the conservative generic analysis in Table E-3. The integration is performed up to the time of secondary side isolation that was credited in the NPSH evaluations (see Section 5.4) to judge the validity of the leakage assessment.

The conservative generic analyses described in this Topical Report produced the time-dependent leakage rates given in Table E-3 based with the corresponding conservative containment pressure (Figure E-12) and the sump liquid temperature (Figure E-13) used in plant-specific NPSH calculations from Section 5.4 to confirm that ECCS pump operation and long-term core cooling can be adequately preserved for any size LOCA in the hot leg U-bend region. The generic inventory loss predicted with this model is integrated and made plant specific by using the SG isolation times and limiting volume of the individual plant steam generators and lines as summarized in Table E-2.

E.4 NPSH Evaluation

The effects of the liquid lost through the primary-to-secondary leak path on the ECCS pump NPSH calculation must be assessed to demonstrate LTC. The simplest and most conservative method is to remove the maximum primary-to-secondary leakage from the limiting existing NPSH analysis for each plant. The difficulty with this method is that most plants do not have sufficient margin in the limiting NPSH analysis to accommodate the total leakage without considering other effects specific to the LOCA that can generate the necessary loads to sever SG tubes. Generally the limiting plant NPSH analysis is performed with boundary conditions and assumptions that minimize the ECCS pump NPSH. Typically the analysis considers a hot leg LOCA with a minimum BWST volume, maximum containment hold-up volumes, and assumptions that maximize the sump liquid temperatures. Provisions for some sump screen blockage and flow loss considering debris loading are included. While a hot leg LOCA may be the limiting break location for the plant NPSH analysis and the SG tube loads analysis, the inputs and boundary conditions used for the NSPH analyses are not the same inputs or boundary conditions that would lead to SG tube failures. In fact, the NPSH calculations typically impose single failure or boundary conditions that minimize the tube loads such that a tube failure would not be expected to occur. Therefore, the limiting plant NPSH calculations need to be reevaluated using a hot leg U-bend transient specific NPSH analysis. The NPSH margin for this hot leg LOCA transient with subsequent SG tube failures is much larger when the boundary conditions that maximize the secondary side leakage are considered.

The LTC ECCS pump NPSH margin is determined based on the elevation of liquid above the ECCS pump, piping flow losses, and the temperature of this liquid without credit for containment overpressure. Since density varies with temperature (increases for decreasing temperature), colder liquids result in a slight increase in elevation head, and the subcooled temperatures provide additional NPSH margin before the pump inlet fluid reaches saturated conditions. The subcooling provides an NPSH credit for accommodating the sump liquid volume decrease from the primary-to-secondary leakage. The potential limiting single failures considered in the analyses were chosen, because they have an effect on the maximum amount of liquid lost and the sump liquid temperature.

Soon after a reactor trip signal, the turbine stop valves (TSVs) receive a close signal. For some plants, a low steam line pressure signal will generate a close signal for the main steam isolation valves (MSIVs). If there is not an automatic MSIV close signal the EOPs have multiple steps that direct the operators to close the valves. The automatic signal or manual closure is completed well before the switch to containment sump as a source for the ECCS pumps. With the MSIVs closed, the liquid lost to the secondary side is limited to the volume of liquid in the SG (beyond the initial volume) and the volume of the steam lines to the MSIV. This assumes that the operators have isolated all other steam drains and steam extraction lines upstream of the MSIV prior to the time the SG fills with liquid and RCS inventory begins to spill into the steam lines. A failure of an MSIV to close in a steam line attached to the affected SG will result in additional liquid lost. The additional volume corresponds to the volume of the steam line piping between the MSIV and the TSV, again assuming that the operators have isolated all other steam drains and steam extraction lines upstream of the TSV prior to the time the SG fills with liquid and RCS inventory begins to spill into the steam lines. In either case, the volume lost has an adverse effect on the liquid inventory used in the sump NPSH calculation.

After the switch to sump recirculation, the DH coolers are used to cool the sump liquid before it is returned to the RCS. A failure that results in the loss of a DH cooler results in less net heat removal which delays the cooldown of the sump liquid temperature. The higher sump liquid temperature also has an adverse effect on the NPSH calculation.

A bounding approach to evaluating the ECCS pump NPSH was performed. For this bounding approach, the failures of both an MSIV and a DH cooler were considered in a composite analysis to minimize the number of cases that need to be evaluated. By using this bounding approach to demonstrate acceptable results, the need for additional calculations is minimized and additional conservatism is retained in the overall method for demonstrating adequate LTC.

The failure of the MSIV results in a volume of liquid lost to the secondary side equal to the volume of the SG (beyond the initial volume) and the volume of a steam line to the TSV. The total volume is dependent on the SG design. The EOTSG secondary volume is slightly larger than the OTSG. In order to bound all of the plants and potential future SG replacements, the volume of the EOTSG is used. The available volume to fill on the secondary side is dependent on the initial power level. At hot zero power, the level is approximately three feet above the upper face of the lower tubesheet (UFLTS). At full power, the level stabilizes after reactor trip and the MFW coastdown to approximately 15 ft. The lower power level minimizes the initial liquid volume in the SG which maximizes the RCS inventory that can be lost to the secondary side. Therefore, to bound all power levels, an additional secondary side liquid volume loss was added to account for the difference in the full power initial liquid inventory versus the low power, secondary side low liquid level limits. Using these inputs, the maximum volume lost to the secondary side was determined. The results for each of the B&W-designed plants are shown on Table E-2 (Parameter "A"). It is noted that the time for operator action to isolate the secondary side was based on the full power case with higher initial liquid inventories, because it shortens the time before the secondary side is filled. The NPSH analyses conservatively used the maximum volume that could be lost to the secondary side based on a low level limit to bound all power levels.

The volume of the steam line attached piping (from the steam lines to the attached piping isolation valves) or any liquid leakage that could occur before these paths are isolated were tabulated by the utilities for each SG. The results are shown on Table E-2 (Parameters "B" and "C", respectively). Parameters "A", "B", and "C" were then added together to determine the total volume lost to the steam lines and attached piping (Parameter "D" on Table E-2). The largest volume for a given steam line and attached piping combination was used to bound all scenarios for each plant. Slight variations of this method were used for some of the plants as described in the following plant-specific analysis sections.

E.4.1 ANO-1

The bounding approach described above was used by Entergy to determine the effect on NPSH for ANO-1. The liquid volume lost to the secondary side through the SG tube rupture was calculated using the following assumptions.

1. The volume of water required to fill the secondary-side steam piping, including branch piping, out to the turbine stop valves (TSVs) is assumed to be lost from the sump inventory. This assumption is very conservative, but bounding, since the operators are directed to isolate a steam generator at the MSIV, if indication of a tube rupture exists. No credible, single, active failure exists that would prevent closure of an MSIV on demand.

2. Branch piping 2" and smaller was ignored, because its volume is insignificant due to the small cross-sectional area of the pipe.

3. Branch lines were assumed to be isolated at the first valve that is either normally closed (and not expected to open following a LOCA) or that is capable of remote, manual isolation from the control room.

The maximum volume lost to the SG and steam lines to the TSV was determined to be 6465.5 ft^3. The volume of all branch piping attached to both steam lines was determined to be 181.27 ft^3. Due to the small volume relative to the steam generator and main steam piping, the total volume of branch piping was conservatively assumed to be lost. Finally, since all of the attached piping isolation valves can be controlled from the control room (see Assumption #3 above) and procedural guidance is provided to initiate isolation, no additional leakage was assumed. The total volume of liquid lost through the SG tube failure was then

Volume lost = E = A + B + C = 6465.5 + 181.3 + 0 = 6646.8 ft^3.

The effect of this amount of lost liquid on the limiting NPSH calculation was evaluated based on the following assumptions.

1. The RB pressure was atmospheric, i.e. no credit for any RB over-pressure was taken. However, the maximum post-recirculation sump temperature of 206.2 F was credited in determining the required NPSH. This temperature was determined considering the failure of a DH cooler.

2. The sump fluid was assumed to be pure water (i.e. no credit was taken for higher fluid densities or saturation property changes due to boric acid or sump pH additives).

For the assumed conditions of this evaluation the NPSH available is 14.4 ft versus a required NPSH of 10.4 ft for the limiting case (i.e. for the ECCS pump with the least NPSH margin). With 4 ft of margin calculated in this evaluation, the base calculation remains bounding.

E.4.2 CR-3

The effect of the liquid lost to the SG secondary side through the SG tube failure is considered in the plant floodup analysis. The resulting sump volume is converted into a level by considering the free volume available in the containment.

The floodup analysis for the hot leg U-bend break concurrent with a steam generator tube rupture was performed using the same calculation technique as the current plant limiting analysis with the exception of the method used to determine the amount of fluid transferred from the BWST to the containment vessel. The current analysis determines the worst-case minimum amount of fluid transferred. The analysis for the hot leg U-bend break concurrent with a steam generator tube rupture determined the amount of fluid transferred using a best-estimate technique with two complete trains of ECCS in operation.

This LOCA scenario is unique in that the typical assumptions made in NPSH analyses minimize the SG tube loads and limit the number of consequential SGTRs. Therefore, the hot leg U-bend analyses have used reasonable assumptions for BWST and ultimate heat sink temperatures as well as other best-estimate to conservative values for key inputs of core decay heat, BWST water volume, containment parameters, etc. Some of the options for obtaining margin for NPSH analyses for the hot leg breaks that can discharge primary inventory through the broken SG tubes include credit for sump liquid subcooling or credit for additional BWST water volume. The option selected for CR-3 credits the additional BWST liquid volume and the liquid subcooling at atmospheric pressure.

The RB flood level determined in the limiting case conservatively assumed instantaneous suction swapover to the RB sump at 15' indicated (16' actual) BWST level. In reality, the ECCS pumps will continue to draw water from the BWST until the BWST isolation valves are isolated. The RB sump suction valves each have a minimum IST stroke time (close-to-open) of 102 seconds. Assuming the operators begin opening these valves immediately at the 15' indicated BWST level, and the ECCS pump flow comes from the BWST until these valves are open, the additional volume added to the RB sump is 1933.6 ft^3.

The analysis considered the sump inventory reduction resulting from the steam generator tube rupture and the failure of a MSIV. This included: (1) the additional fluid to fill the steam generator on the secondary-side up to the main steam line, (2) the volume of fluid needed to fill a main steam line and attached piping, and (3) leakage through the steam traps and other flow paths that are not automatically isolated for one hour after the liquid reaches the steam lines.

The maximum volume lost to the SG and steam lines to the TSV was determined to be 5753.5 ft^3. The volume of the branch piping attached to the affected steam lines was determined to be 300 ft^3. Since the steam traps and other flow paths are not automatically isolated, leakage out of the secondary system will occur until operator action can be taken to close the isolation valves. The leak rate from the primary-to-secondary side of the OTSG at the time the liquid level in the OTSG reaches the main steam lines is 24 ft^3/min. Assuming one hour to isolate the required valves after the OTSG is filled and assuming the leak rate does not decrease as RCS/RB pressure decreases yields the integrated volume of leakage of 1440 ft^3. The volume lost is partially offset by the additional volume of additional injection from the BWST, 1933.6 ft^3. The total volume of liquid lost through the SG tube failure was then

$$\text{Volume lost} = E = A + B + C - \text{Additional BWST Vol Injected}$$
$$= 5753.5 + 300 + 1440 - 1933.6 = 5559.9 \text{ ft}^3.$$

The effect of this amount of lost liquid on the limiting NPSH calculation was evaluated. The additional lost volume reduced the minimum RB water level from 2.12 feet to 1.58 ft above the basement floor.

Progress Energy has installed a debris interceptor on the 95 ft elevation at CR-3. If this interceptor is conservatively assumed to be completely blocked, the minimum RB level must be above the interceptor so that flow can continue to recirculate through the sump. At the ECCS flow, the RB water level must be at least 1.53 feet, which is less than the RB water level with the extra volume removed due to the SG tube failure.

E.4.3 DB-1

The effect of the liquid lost to the SG secondary side through the SG tube failure is considered in the plant floodup analysis, which is performed by determining the individual components that contribute to the sump inventory (BWST, CFT, etc.) and those that are diverted away from the sump (condensation, fluid in transit, RCS leakage, steam generator tube rupture blowdown, etc.). The resulting sump volume is converted into a level by considering the free volume available in the containment.

The floodup analysis for the hot leg U-bend break concurrent with a steam generator tube rupture was performed using the same calculation technique as the current plant limiting analysis with the exception of the method used to determine the amount of fluid transferred from the BWST to the Containment Vessel. The current analysis determines the worst-case minimum amount of fluid transferred. The analysis for the hot leg U-bend break concurrent with a steam generator tube rupture determined the amount of fluid transferred using a best-estimate technique with two complete trains of ECCS in operation.

This LOCA scenario is unique in that the typical assumptions made in NPSH analyses minimize the SG tube loads and limit the number of consequential SGTRs. Therefore, the hot leg U-bend analyses have used reasonable assumptions for BWST and ultimate heat sink temperatures as well as other best-estimate to conservative values for key inputs of core decay heat, BWST water volume, containment parameters, etc. Some of the options for obtaining margin for NPSH analyses for the hot leg breaks that can discharge primary inventory through the broken SG tubes include credit for sump liquid subcooling or credit for additional BWST water volume. The option selected for DB credits the additional BWST liquid volume.

The best-estimate technique is based on: (1) the elevation of the BWST low level setpoint and, (2) the nominal elevation of the setpoint for the permissive to transfer emergency pump suction from the BWST to the Emergency Sump. The best-estimate amount of fluid transferred from the BWST to the Containment Vessel was determined to be 399,060 gallons. This value is 11 percent higher than the worst-case minimum value utilized for the floodup analyses of other transients (i.e., 360, 000 gallons).

The analysis considered the sump inventory reduction resulting from the steam generator tube rupture and the failure of a MSIV. This included: (1) the additional fluid to fill the steam generator on the secondary-side up to the Main Steam line and, (2) the volume of fluid needed to fill a Main Steam Line and attached piping including the piping downstream of the Main Steam Isolation Valve. In addition, procedural guidance is provided to isolate a steam generator at the MSIV (including any steam drains, turbine driven AFW flows or other steam leakage) if indication of a steam generator tube rupture exits. In the unlikely event that the MSIV fails to close, an assessment was performed to show that sufficient time is available (i.e. 67 minutes for 4 free span tube severs) for the Shift Supervisor and the Technical Support Center (TSC) to provide the necessary guidance to isolate any lines downstream of the MSIV prior to filling the steam lines with fluid.

The maximum volume lost to the SG and steam lines to the TSV was determined to be 6111 ft^3. The volume of the branch piping attached to the main steam line of the affected steam generator was determined to be 260 ft^3, which includes a 20% increase in volume for conservatism. Due to the small volume relative to the steam generator and main steam piping, the total volume of branch piping was conservatively assumed to be lost. Finally, since procedural as well as TSC guidance for providing isolation within 67 minutes was assessed to be adequate, no additional leakage was considered. The total volume of liquid lost through the SG tube failure was then

$$\text{Volume lost} = E = A + B + C = 6111 + 260 + 0 = 6371 \text{ ft}^3 \text{ (\~{}47,700 gal)}$$

The floodup elevation for a hot leg U-bend break concurrent with a steam generator tube rupture was determined to be 566.93 feet, International Great Lakes Datum. This value is slightly greater than the current analysis. Therefore, all analyses that utilize the floodup level as an input remain bounding, including the NPSH analyses.

E.4.4 TMI-1

The effect of the liquid lost to the SG secondary side through the SG tube failure is considered in the plant floodup analysis, which is performed by determining the individual components that contribute to the sump inventory (BWST, CFT, etc.) and those that are diverted away from the sump (condensation, fluid in transit, RCS leakage, steam generator tube rupture blowdown, etc.). The resulting sump volume is converted into a level by considering the free volume available in the containment.

The floodup analysis for the limiting break concurrent with a steam generator tube rupture was performed. The analysis considered the sump inventory reduction resulting from the steam generator tube rupture and the failure of an MSIV to close after receiving the isolation signal. This included: (1) the additional fluid to fill the steam generator on the secondary side up to the Main Steam Line and, (2) the volume of fluid needed to fill a Main Steam Line and attached piping between the SG and the credited isolation valves in the SG that is being overfilled by the SGTR. An assessment was performed to show that sufficient time is available for the Shift Supervisor and the Technical Support Center (TSC) to provide the necessary guidance to isolate any open lines attached to the main steam lines between the broken loop SG and the TSVs. This isolation can be performed prior to the time (i.e. 67 minutes for 4 free span tube severs) the steam lines begin to fill with liquid.

The maximum volume lost to the broken loop SG and steam lines to the TSV was determined to be 7500 ft^3. This volume includes 2230 ft^3 for the main steam piping run, and a volume of 4469 ft^3 to account for OTSG liquid inventory. A volume of 345 ft^3 includes the main steam line branch piping and a volume of 456 ft^3 margin is added to round the total up to 7500 ft^3. Finally, since procedural as well as TSC guidance for providing isolation within 67 minutes was assessed to be adequate, no additional leakage was considered. The total volume of liquid lost through the SG tube failure was then

$$\text{Volume lost} = E = A + B + C = (2230 + 4469) + (345 + 456) + 0 = 7500\ ft^3\ (\sim 56{,}108\ \text{gal})$$

The worst case LOCA pump NPSH requirements have a margin of 1.5 ft to the required floodup level. The floodup elevation for a limiting break concurrent with a steam generator tube rupture is reduced by 0.69 feet. This value is within the available margin, and the pump operability is supported.

E.5 Secondary Piping Integrity

The hot leg LOCA with consequential SGTR during the ECCS refill of the RCS can also refill the secondary side with subcooled RCS fluid that could create steam condensation related loads that have not been considered relative to the secondary pipe structural integrity. The secondary side structural integrity is critical, because with ruptured SG tubes this piping becomes the containment barrier that limits the dose and the volume of RCS and sump liquid that can be lost.

The ECCS refill of the RCS following the hot leg U-bend LOCA subcools the steam generator tubes which condenses steam on the secondary side and drops the secondary side pressure to a saturation temperature that is below the fluid temperature remaining in the MFW lines. The MFW fluid flashes at this point and the liquid displaced by the feedwater flashing delays the cooldown of the tubes and augments the overall SG shell cooling, because the collapsed water level is higher on the SG downcomer wall. This flashing is a benefit that was not directly credited in the TTS temperature difference analyses; however, it is a real phenomenon that may present challenges to the pipe integrity if a steam condensation water hammer could occur when the primary-to-secondary RCS leakage refills the steam generator tube bundle above the MFW nozzle locations allowing liquid to refill the MFW piping. After the MFW lines refill, the RCS leakage into the SG can refill the tube bundle above the upper shroud pressure taps and ultimately above the top of the shroud allowing the steam lines to be filled with liquid.

Steam condensation water hammer is a fluid transient wherein a steam void has been introduced into a liquid-filled system, or liquid water has been introduced into a steam-filled system. If system conditions are such that significant heat transfer from the steam to either the liquid, or the pipe walls, or both can occur, the steam void can rapidly collapse, accelerating the adjacent liquid. The resulting motion of the liquid (acceleration, and subsequent deceleration) can potentially impose large system pressures on the system piping.

Reference [E-5] lists six conditions that must be present for a steam condensation water hammer to occur. These are:

1. The pipe must be almost horizontal,
2. The subcooling must be greater than 20C (36F)
   (Both References [E-5] and [E-6] state/imply that the critical subcooling margin increases with increasing pressure. Reference [E-5] states that the minimum subcooling margin of 20C pertains to "low pressure systems", and Figure 2-2 of Reference [E-5] indicates that a "low pressure system" is on the order of ~32 psia.)
3. The L/D must be greater than 24,
4. The Froude number must be less than one,
5. There should be a void nearby, and
6. The pressure must be high enough so that damage occurs (above approximately 10 atmospheres).

Reference [E-6] also addresses conditions necessary to induce a steam condensation water hammer, and indicates that:

1. Water hammer occurrence criteria were not greatly influenced by fluid velocity,
2. Water hammers occur around a void fraction of 0.5,
3. Heat transfer to the pipe walls is significant (i.e., the pipe walls represent a large heat sink if they were cool prior to coming in contact with the steam),
4. The degree of subcooling is dependent upon system pressures, for example, at 0.6 MPa (87 psia), a minimum subcooling of ~24 K (43 F) was necessary for a steam condensation water hammer to occur, while at 1.1 MPa (160 psia) the subcooling necessary for water hammer increased to 37 K (67 F).

Both References [E-5] and [E-6] indicate that without sufficient subcooling, a steam condensation water hammer will not occur. Reference [E-2] indicates that as system pressure increases, the degree of subcooling necessary to cause a water hammer also increases. This is illustrated by the data plotted in Figure E-14.

The RELAP5/MOD2-B&W analyses of the subject transient from Section E.3 were reviewed to determine the fluid temperatures that would begin to refill the MFW lines. The fluid temperatures in the upper downcomer after the SG tube rupture had refilled the steam generator to the MFW nozzle elevation were relatively warm with a maximum subcooling of 20 F at the time the lines would begin to fill. This fluid subcooling is used with secondary side pressures of 25 psia and lower when the MFW line refill begins. The rate of liquid refill is approximately equal to the tube leakage rate of between 25 and 30 ft^3/min over the first 15 to 55 minutes after the SGTR occurs.

The continued leakage from the RCS into the secondary side raises the levels and fills the SG secondary side. There are two possible paths for liquid to reach the steam annulus: through the annular holes around the upper pressure taps or by complete refill and spilling over the top of the shroud. At 67 minutes after reactor trip, water with a maximum subcooling of <35 F with pressures of 25 psia and lower begins flowing into the steam lines. The rate of fill at this time is slightly less than 25 ft^3/min.

The subcooling of 20 F present during the MFW line refill phase is well below the steam condensation water hammer threshold of 36 F identified in Reference [E-5], and the occurrence of a steam condensation water hammer is precluded. The subcooling present during the spillover phase of 35 F approaches (but is below) the 36 F steam condensation water hammer threshold identified in Reference [E-5]. However, the system pressures are low (well below the 10 atmosphere criteria), and not sufficient to cause system damage in the unlikely event of a steam condensation water hammer.

Consequently, based upon the transient results summarized herein, and the steam condensation water hammer criteria discussed in References [E-5] and [E-6], (in particular the criterion pertaining to minimum subcooling required for steam condensation water hammer occurrence and minimum system pressures required to create piping loads large enough to damage piping), the following conclusions can be drawn:

1) There will likely be insufficient subcooling to incite a steam condensation water hammer in the feedwater and steam systems during the subject transient, and
2) In the unlikely event that the minimum subcooling margin for steam condensation water hammer is exceeded, system pressures will be insufficient to create piping loads large enough to damage system piping.

E.6 Summary and Conclusion

The demonstration of 10 CFR 50.46 adequate long-term core cooling was provided in this appendix based on consideration of the probability of tube rupture, LOCA analyses with consequential SGTRs, containment analyses, credit for EOP actions to isolate the secondary side to support utility NPSH analyses, and water hammer evaluations to support the steam and feedwater piping integrity. The realistic probability of a single tube rupture was calculated to be roughly four percent based on typical as-found tube flaw distributions in the steam generators. The LOCA analyses were performed with four free span tube ruptures (which coincides with a probability of less than 10^{-6}) to provide ample margin to address potential leakage from some unexpected tube degradation mechanism. The generic LOCA analysis used a composite model considering all the B&W-plants participating in the work effort. It used the smallest containment building and considered the steam line geometry that maximized the SGTR leakage. A range of hot leg LOCA break sizes were considered from the break range that could reasonably produce tube stresses that could create a consequential SGTR. The tube load and containment pressure considered the largest break size and the SGTR considered the smallest one to ensure the analyses were overall bounding. Single failure of a DH cooler was used to maximize the sump liquid temperature and containment pressure to maximize the SGTR leakage and minimize NPSH margin. Failure of an MSIV was considered to maximize primary side inventory loss to the secondary side. The inventory loss considered the automatic and EOP action times to isolate valves for lines which included the main steam line, drains, steam admission lines for turbine-driven EFW pumps. Secondary side inventory losses were considered based the plant specific secondary side volumes with consideration of low core power initial secondary side inventories, replacement steam generator volume design changes, and attached piping volumes.

The primary-to-secondary leakage calculated with this conservative modeling was removed from the sump liquid inventory in the utility NPSH analyses for this hot leg LOCA scenario. The plant-specific NPSH calculations credited operator action times to isolate the secondary side based on the EOP or technical support center (TSC) guidance to mitigate the consequences of this LOCA scenario. They each demonstrated that adequate NPSH was maintained throughout the transient, such that long-term pumped ECCS injection could be maintained and adequate to abundant LTC provided. Therefore, these analyses conclude that the B&W-designed plants remain in compliance with 10 CFR 50.46 for any hot leg LOCA. This demonstrated compliance with the regulations supports the risk-informed approach to conclude that thermal loads from RCS pipe breaks could be excluded from the mechanical considerations for the steam generator tubes, tube repair products, and tube-to-tubesheet joints.

E.7 References

E-1. T. L. George, et. Al, "GOTHIC Containment Analysis Package Technical Manual, Version 7.1, NAI 8907-06 Rev. 13, January 2003.

E-2. AREVA Proprietary Topical Report BAW-10164P-A, Rev. 4, "RELAP5/MOD2-B&W – An Advanced Computer Program for Light Water Reactor LOCA and Non-LOCA Transient Analysis", November 2002.

E-3. AREVA NP Topical Report BAW-10252(P)-A, Rev 0, "Analysis of Containment Response to Postulated Pipe Ruptures Using GOTHIC," September 2005.

E-4. "Steam Generator Degradation Specific Management Flaw Handbook", Report 1001191, Final Report, January 2001, EPRI, Palo Alto, Ca.

Note: The referenced flaw handbook is the latest released version. However, it is currently being revised to incorporate new equations which are based on recently completed test programs. The revisions include new failure equations for tubes containing circumferential degradation and also equations to account for the effects of contributing loads (non-pressure axial and bending loads) on the rupture strength of steam generator tubing. These new equations are used for this LBLOCA evaluation. The revised flaw handbook is expected to be issued during 2007.

E-5. NUREG/CR-6519, Screening Reactor Steam/Water Piping Systems for Water Hammer, September, 1997.

E-6. FEDSM99-6899, Experiments and Model for Condensation-Induced Water Hammer in Large Diameter Horizontal Piping, Proceedings of the 3rd ASME/JSME Joint Fluids Engineering Conference, July, 1999.

E-7. AREVA Proprietary Topical Report BAW-10192P-A, Rev. 0, "BWNT LOCA – BWNT Loss-of-Coolant Accident Evaluation Model for Once-Through Steam Generator Plants", June 1998.

Table E-1. Key Boundary Conditions for Leak Rate Calculation

Parameter	Leak Rate Analysis Value	Comment
Primary-to-Secondary Leak Area	0.007 ft^2 from each side of the guillotine tube break	Equivalent to approximately 4 severed tubes in the free span.
RCS Break Size, ft^2	0.75	Increases RCS long term pressure compared to larger breaks. Smaller breaks will not produce the TTS ΔT to rupture SG tubes.
RCS Break Location	Hot Leg U-Bend	Limiting location.
Core Power, MWt	2772	Bounds current plant operating power levels.
Decay Heat Multiplier	1.0 * 1971 ANS fission products plus B&W heavy isotopes.	10% higher than Appendix A calculation to maximize leakage and minimize NPSH.
BWST Temperature, F	90	Reasonably high normal value – 50 F higher than Appendix A calculation.
ECCS Flow Rates	2 pumps with best-estimate to runout flows.	Same as Appendix A calculation.
Containment Spray Flow Rates	2 pumps	Twice the minimum flow rate.
Building Coolers	Containment cooling from the building coolers minimized	Generic minimum value to maximize containment pressure.
Containment Free Volume, ft^3	$1.90x10^6$	Minimum of B&W plants considered including a 5% reduction from the nominal value.
Initial Pressure Inside Containment, psig	+3	Maximum Tech Spec value of B&W plants considered.
Initial Temperature Inside Containment, F	130	Reasonably high value based on plant operating data.
Ultimate Heat Sink Temperature, F	95	Reasonably high value based on plant operating data.

Table E-2. SG and MSL Volumes and Fill Times

Parameter	Plant[Note 1]							
	ANO-1[Note 2]		CR-3[Note 3]		TMI-1[Note 4]		DB-1[Note 5]	
	SG-A	SG-B	SG-A	SG-B	SG-A	SG-B	SG-A	SG-B
A. Leakage Volume to fill to TSV (bounding), ft^3	6465.5	6264.7	5239.1	5753.5	6402	6699	6111	5001
B. Volume of Attached Piping to Isolation Points, ft^3	181.27		300		801[Note 6]		260	
C. Integrated Volume of Leakage if $T_{isolation} > T_{liq\ fill}$, ft^3	0		1440		0		0	
D. Total Volume lost to steam lines and attached piping, ft^3 = "A" + "B" + "C"	6646.8	6446.0	6979.1	7493.5	7203	7500	6371	5261
E. Volume to be used in NPSH calculation, ft^3 = maximum of "D" for SG-A versus SG-B	6646.8		7493.5		7500		6371	

<u>Notes for Table E-2:</u>

1. Duke Energy is not currently participating in this project, therefore the volumes and times were not calculated for ONS.
2. See Section E.4.1 for the basis and assumptions used to determine these values.
3. See Section E.4.2 for the basis and assumptions used to determine these values. There is additional conservatism in the steam line volume reported in the Row A for CR-3 because of the four steam line arrangement (2 from each SG). The steam line volume given includes both steam lines to the TSVs for each respective SG. At CR-3, the two steam lines between the MSIV and TSV are separated such that a single failure of one MSIV would fill only one steam line downstream of the failed MSIV.
4. See Section E.4.4 for the basis and assumptions used to determine these values.
5. See Section E.4.3 for the basis and assumptions used to determine these values.
6. The largest volume of attached piping was estimated as 345 ft^3 for TMI, but a margin was added to total 7500 ft^3 of liquid lost from the NPSH analysis. The margin of ~456 ft^3 is reflected in the volume listed for the attached pipe and easily accounts for approximations or simplifications used in the attached volume calculations.

Table E-3. Primary-to-Secondary Side Leak Rates for Four Ruptured SG Tubes

Transient Time Seconds	Time after SGTR seconds	Time after SGTR minutes	Leak Rate ft^3/min	Integrated Leakage ft^3
0	-	-	0	0
1200	0	0	31	0
2100	900	15	31	465
2400	1200	20	30	615
2700	1500	25	28	755
3000	1800	30	27	890
3600	2400	40	26	1150
4500	3300	55	25	1525
5100	3900	65	24	1765
5700	4500	75	23	1995
6300	5100	85	22	2215
6900	5700	95	21	2425
15000	13800	230	20	5125
>15000	>13800	>230	20	Time Dep

Figure E-1. Tube Axial Loads

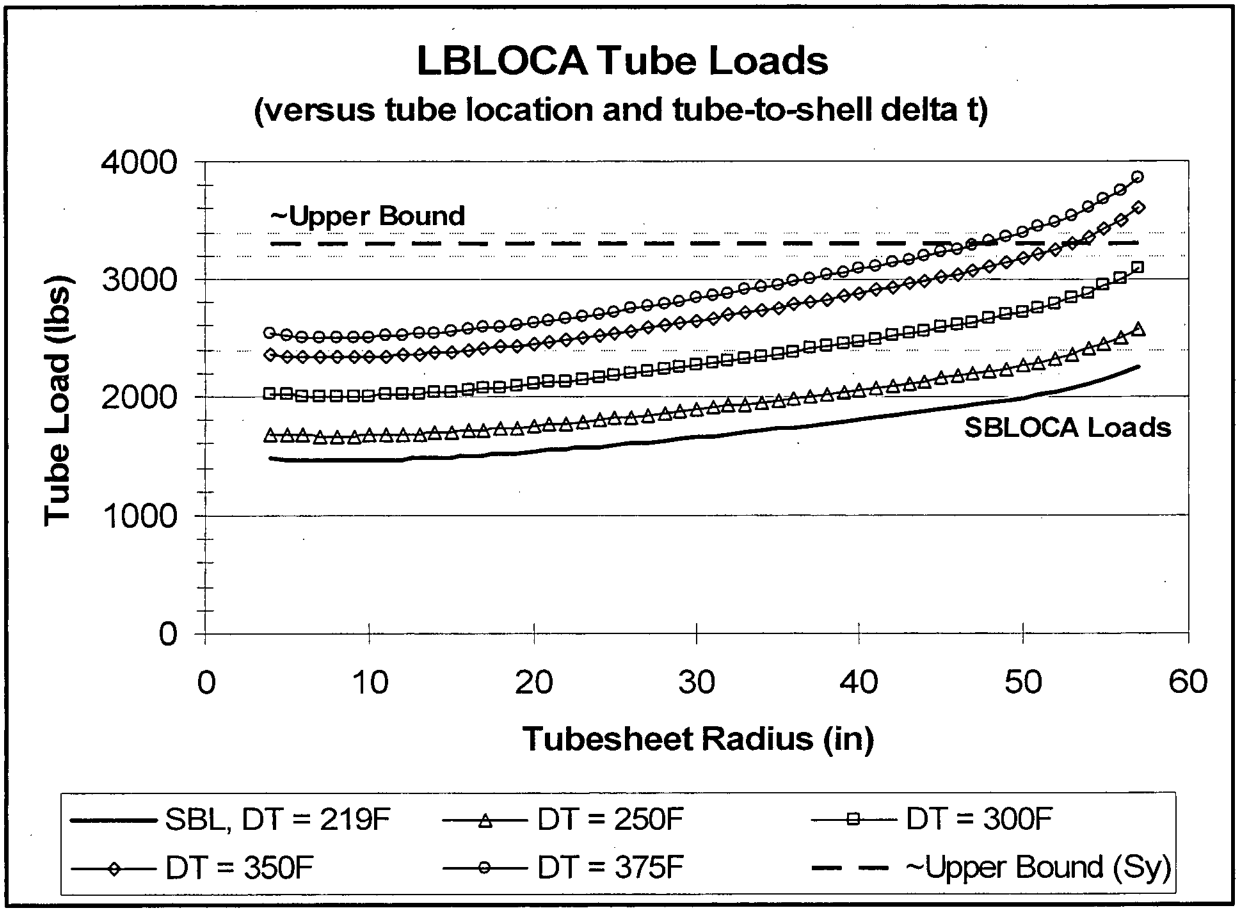


Figure E-2. Allowed Axial Load vs Circumferential Flaw PDA

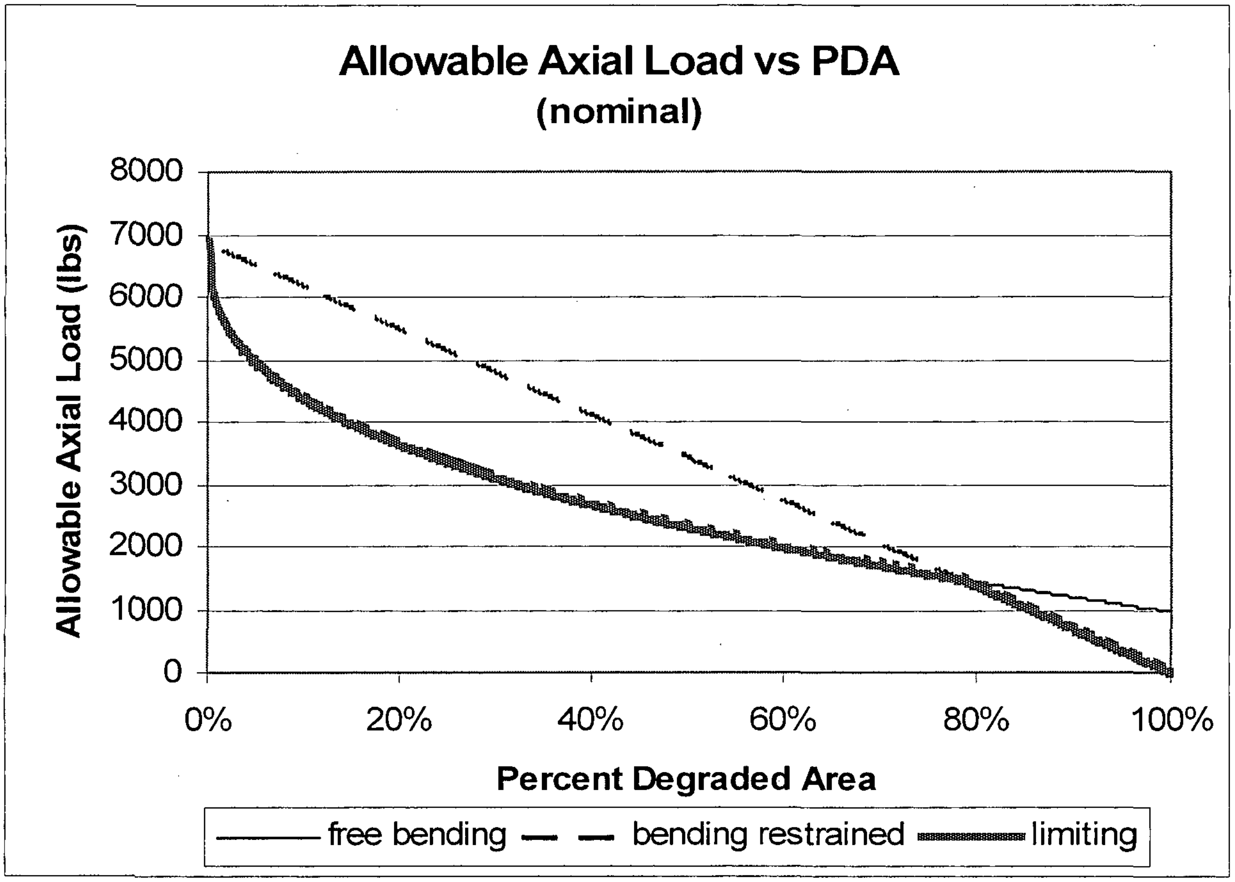


Figure E-3. Allowable Free Span Flaw PDA

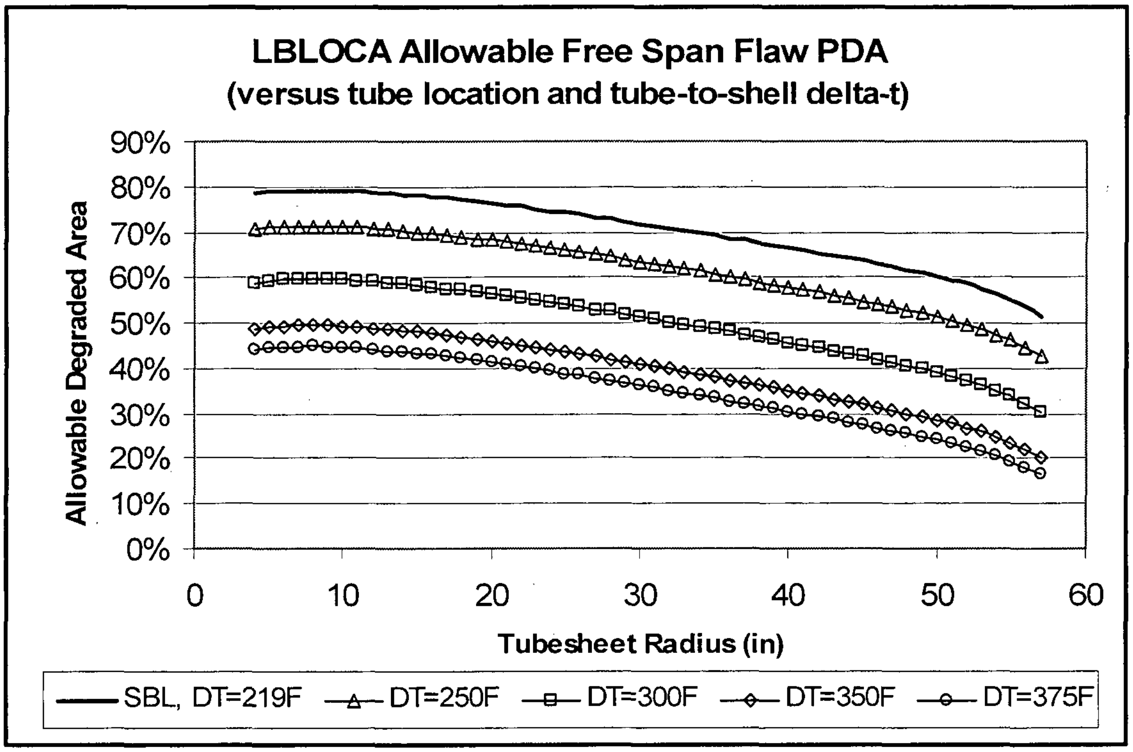


Figure E-4. Allowable PDA for Bending Restrained Flaw

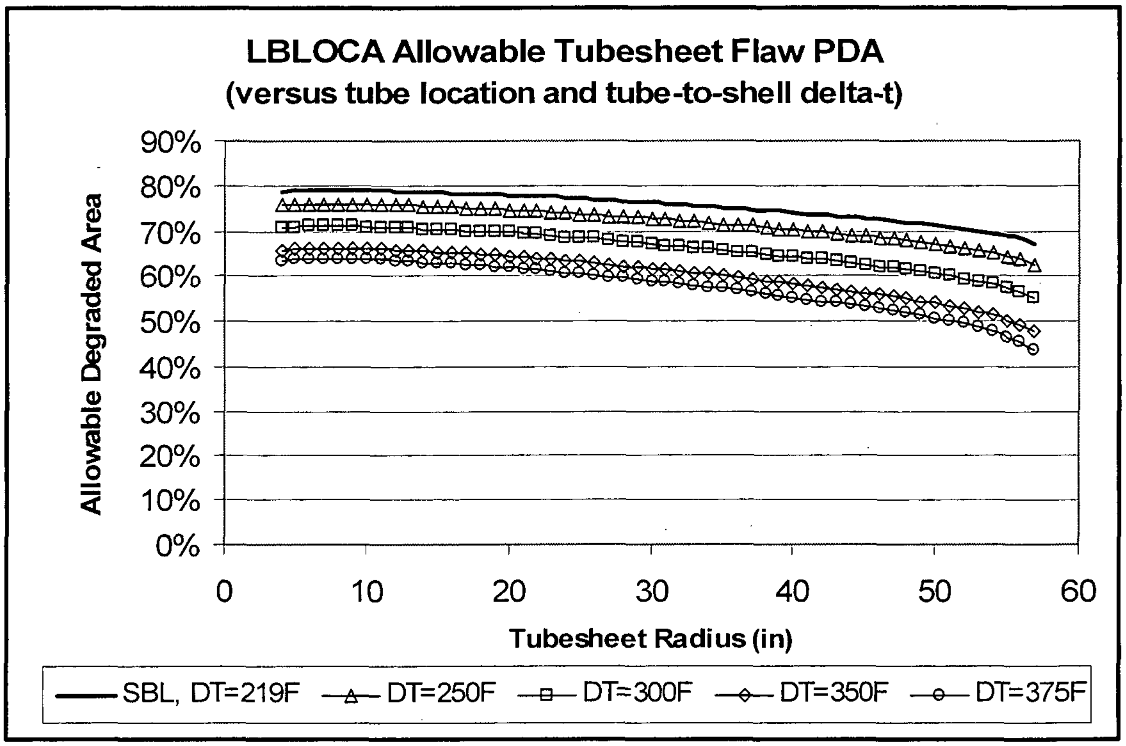


Figure E-5. Schematic of an OTSG Tube

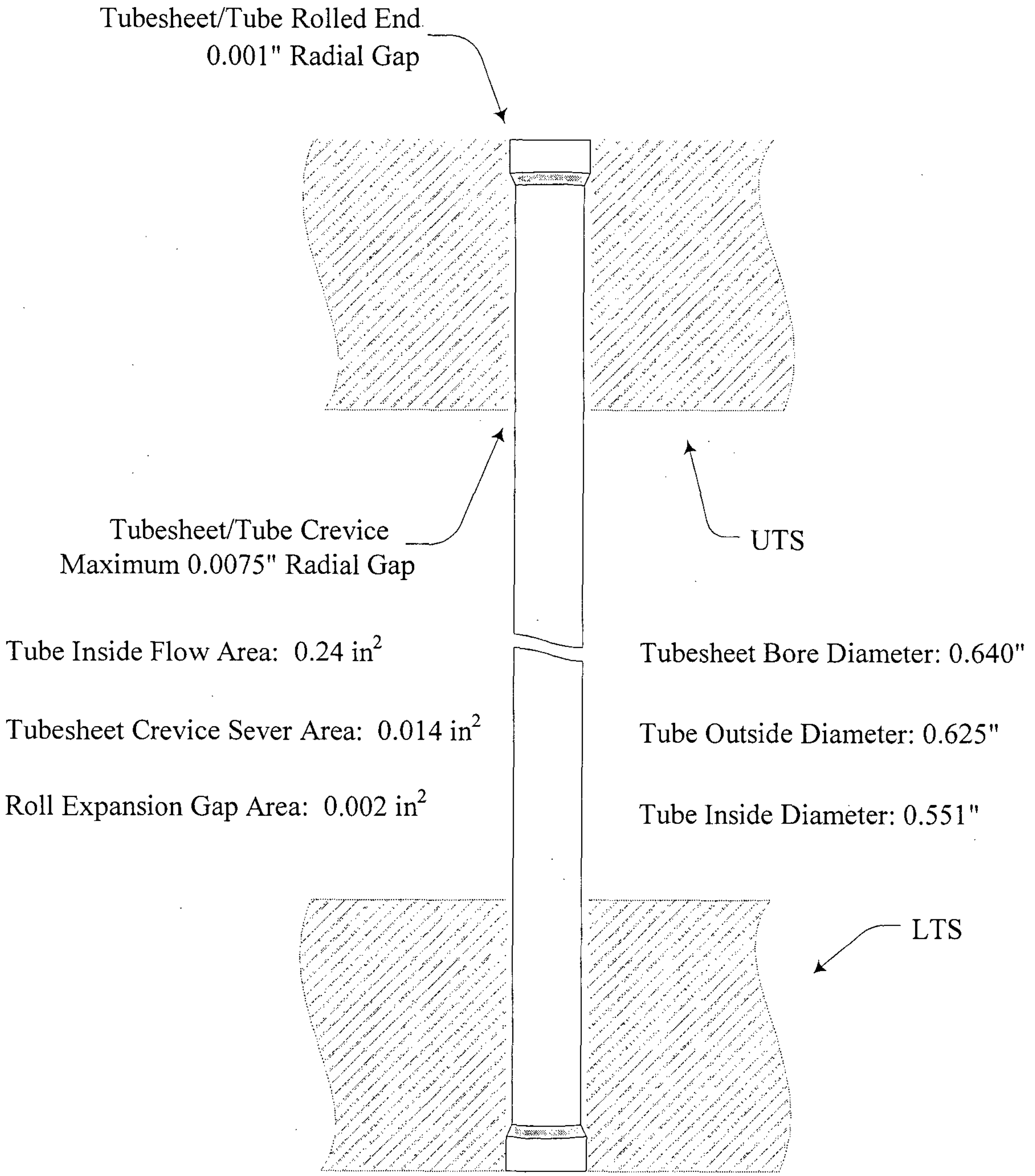


Figure E-6. Distribution of Circumferential Lengths for Free Span Degradation at Oconee Unit 1

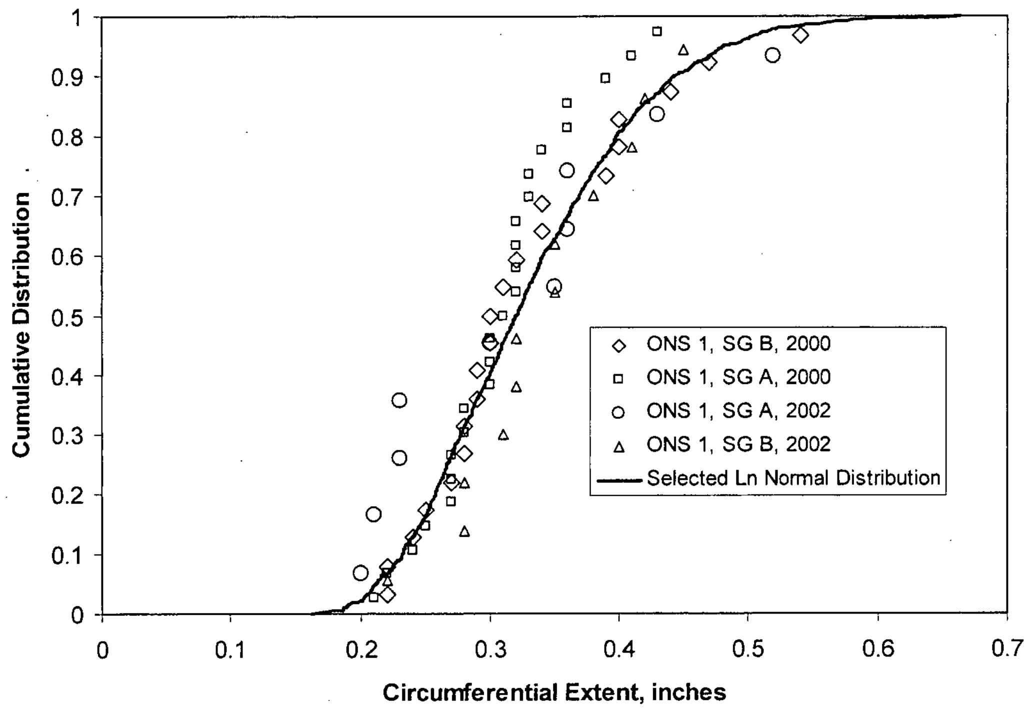


Figure E-7. Distribution of Maximum Depth for Free Span Degradation at OTSG Plants

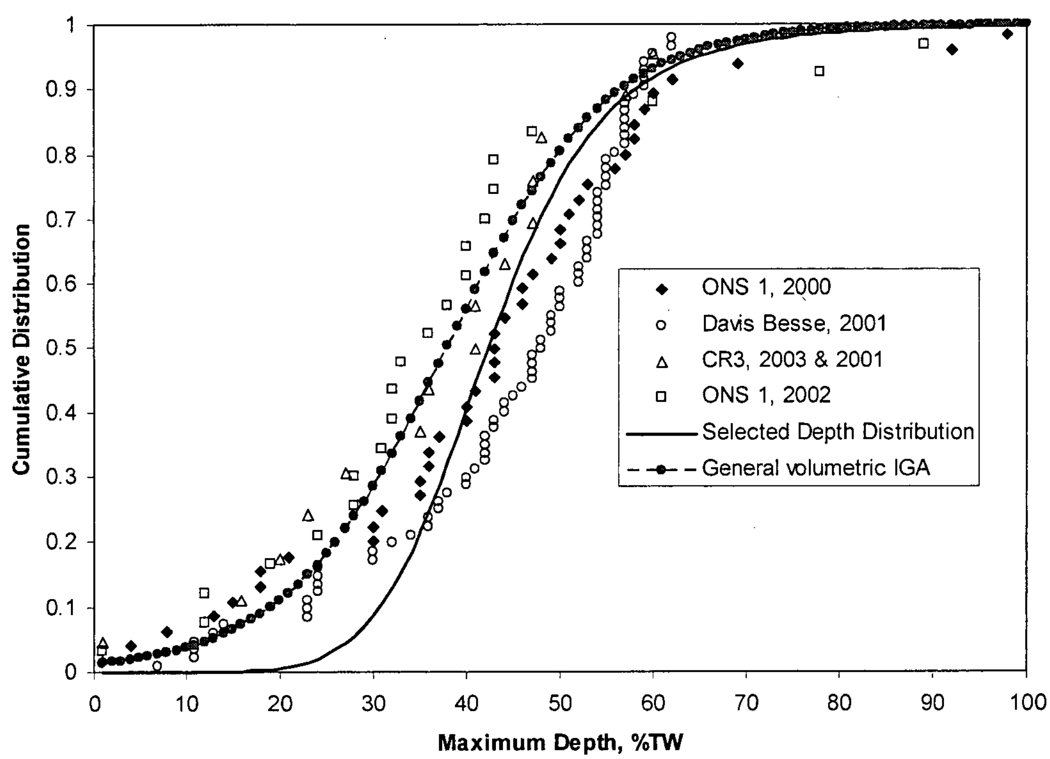


Figure E-8. Distribution of End of Life Maximum Depths, Nominal, Lower and Upper Estimates

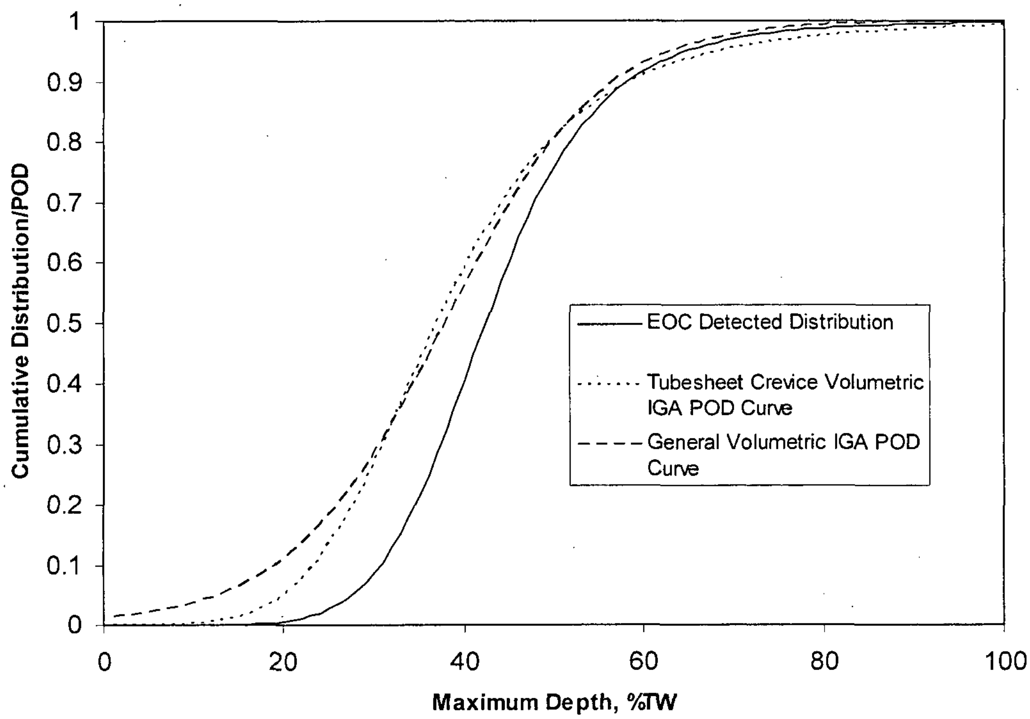


Figure E-9. Probability of Tube Sever per Indication versus Axial Load

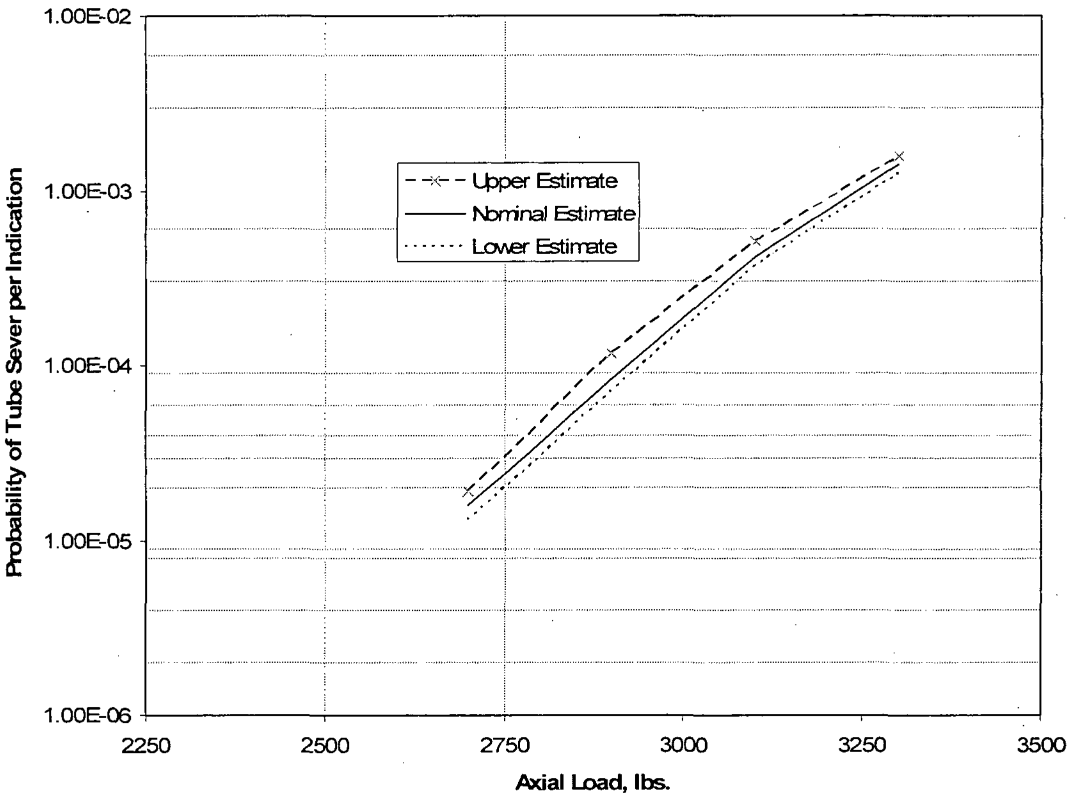


Figure E-10. Probability of Tube Occurrence versus Number of Tube Severs, Nominal Estimate

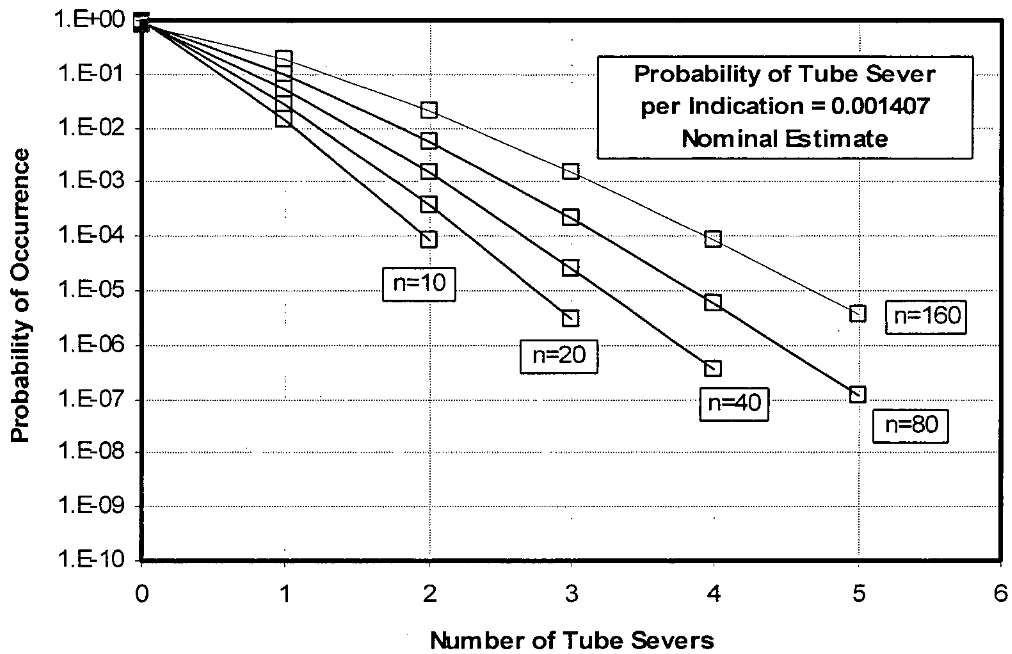


Figure E-11. Probability of Tube Occurrence versus Number of Tube Severs, Upper Estimate

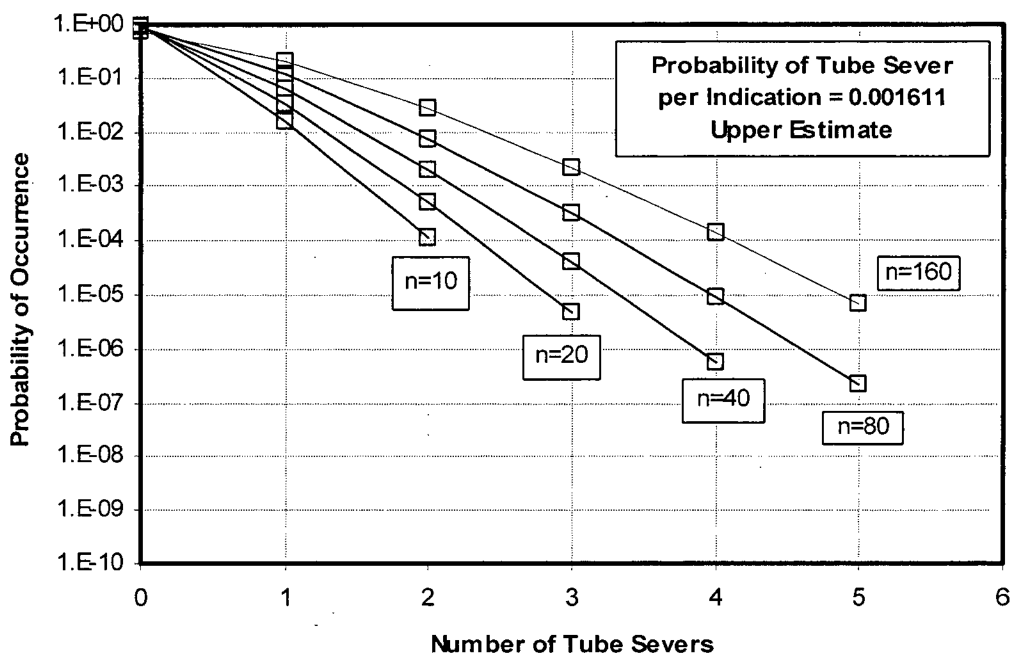


Figure E-12. Containment Pressure

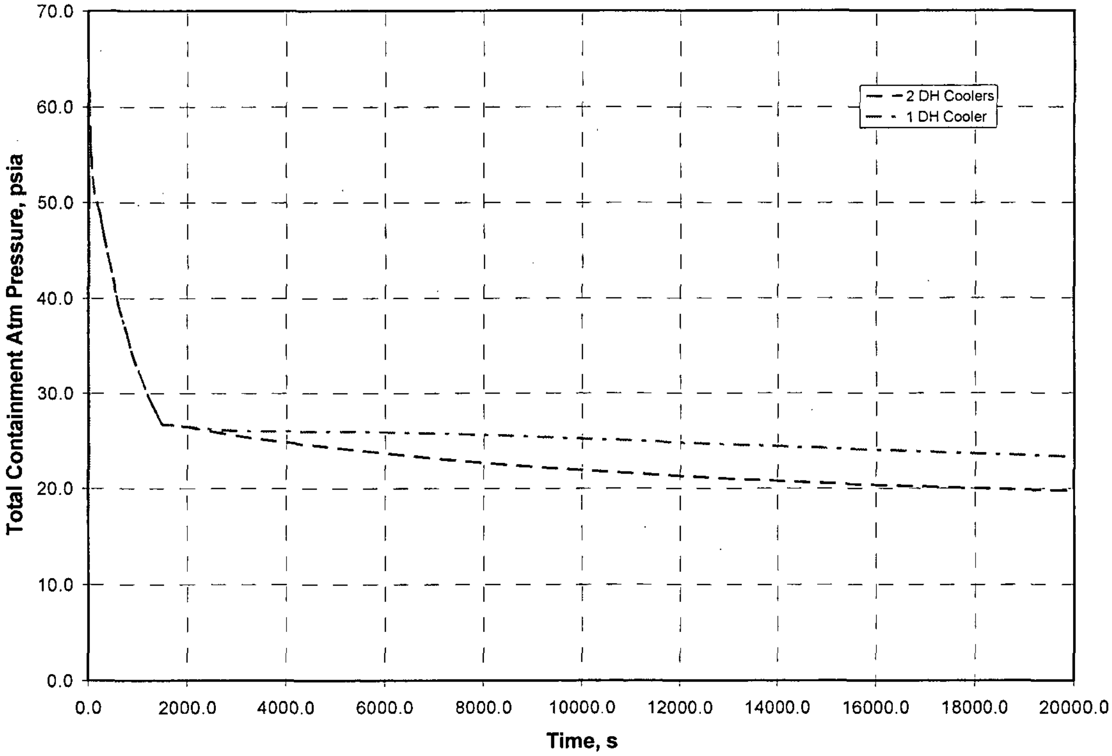


Figure E-13. Containment Sump Liquid Temperature

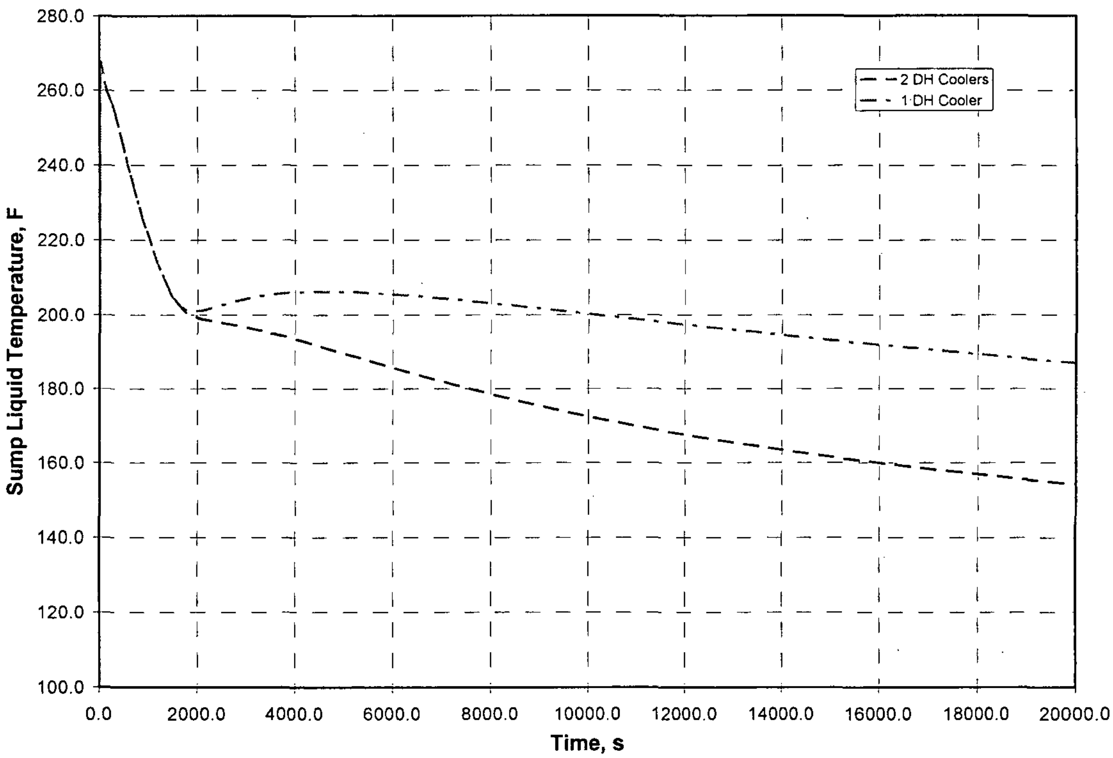
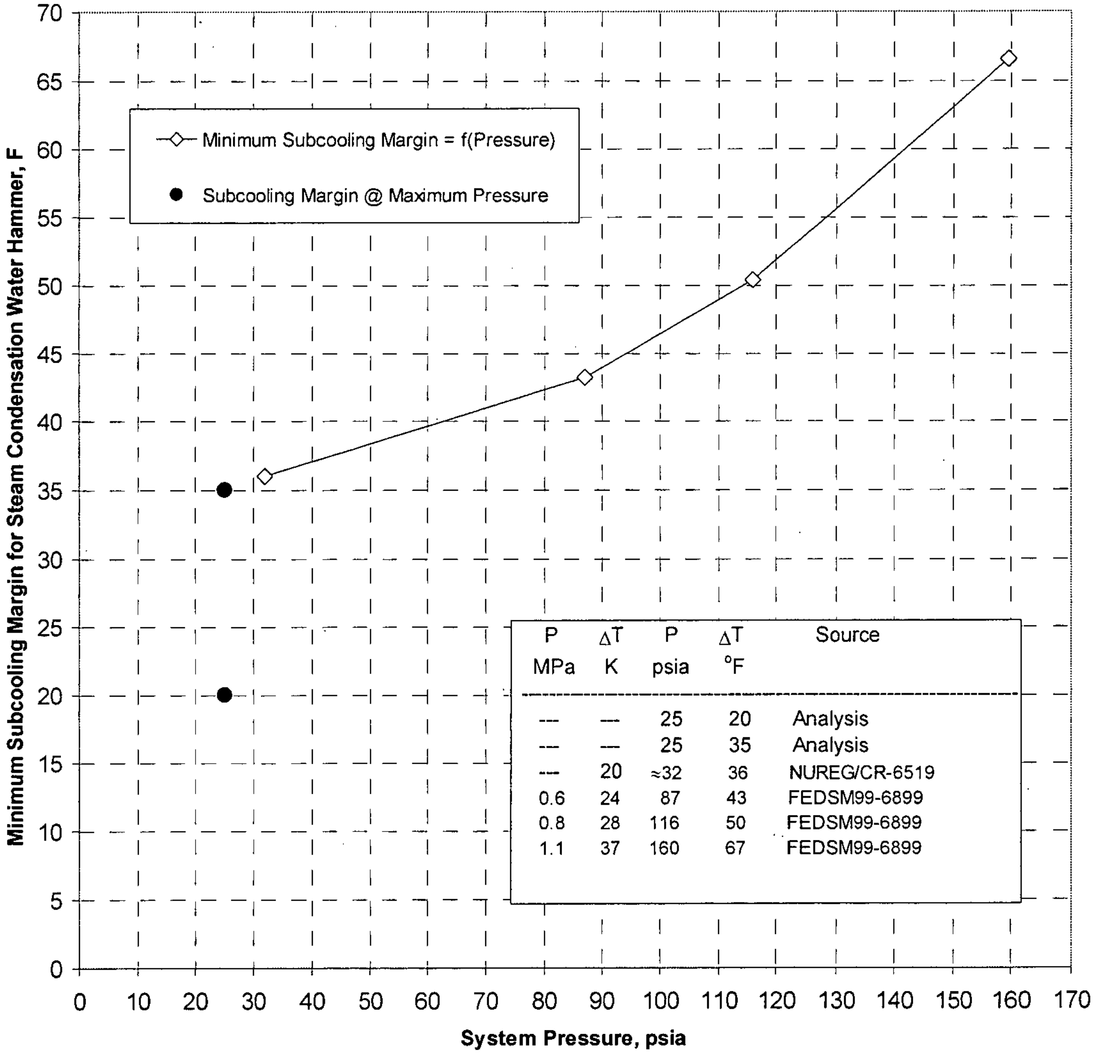


Figure E-14. Subcooling Margin for Steam Condensation Water Hammer



Appendix F

Dose Consequences Following a Hot Leg U-Bend Break

Note: Appendix F was added in Revision 2 of BAW-2374, however, no margin bars are shown.

Table of Contents

List of Figures

List of Tables

Dose Consequences Following a Hot Leg U-Bend Break

F.1 Introduction and Background

There are three fission product containment barriers which must be breached for dose consequences of any accident to affect the public. The fuel pin cladding is the primary boundary that contains the fuel pellets and permits movement and transport of the irradiated fuel. In the event that there is cladding failure, the reactor coolant system (RCS) piping and steam generator (SG) tubes provide a second boundary to confine the fission products. In the unlikely breach of the RCS piping or SG tubes, the containment building and secondary piping provides the third barrier that shields the public and utility workers from receiving excessive radiation doses.

Safety analyses are performed with different postulated accidents, such as loss-of-coolant accidents (LOCAs) or steam generator tube ruptures (SGTRs), to produce different challenges to these fission product barriers. A LOCA results in the breach of the RCS boundary and loss of RCS coolant that can, under certain conditions, result in marginal core cooling from inadequate water inventories such that the fuel pins heat up. When the RCS pressure decreases below the fuel pin internal gas pressure, the outward hoop stresses can result in ballooning and rupture of the cladding when temperatures reach a range between roughly 1300 to 1800 F. If rupture is predicted, fission products are released from the fuel pin and can ultimately flow through the RCS breach into the containment. In this case, two of the three fission product barriers fail but the containment building remains and contains the fission product release.

In the event of a SGTR, the RCS is breached. RCS fluid flowing into the secondary side can flow through the steam lines which pass through the containment boundary wall. In this case, the steam and feedwater line piping and isolation valves, which are located outside the containment building, act as the third containment barrier. However, there are main steam safety valves (MSSVs) that open if the secondary side pressure exceeds their lift setpoint. There may also be a turbine driven emergency feedwater (EFW) pump that uses steam from the secondary side and exhausts to the atmosphere. The MSSVs or turbine driven steam flow are potential open flow paths in the third containment barrier. However, for a SGTR, analyses demonstrate that the core cooling remains adequate such that the fuel pin cladding remains intact and effectively protects one fission product barrier.

A relatively large hot leg U-Bend LOCA, under certain conditions, may cause a consequential SGTR from the ECCS refill that produces large tensile stresses on the SG tubes. The large loads could rupture degraded tubes. A SGTR as a consequence of the refill from a LOCA results in a second breach of the RCS and provides a path for possible fission products to flow with the fluid to the SG secondary side. Isolation of the secondary side by automatic valve isolation and operator actions not only restricts the leakage, which is necessary to preserve adequate ECCS pump NPSH, but it also stops the flow that may contain radioactive contaminants that could increase the dose to the operators or public. Further demonstration that the fuel cladding remains intact throughout the transient greatly reduces the fission product source.

The overall resolution of this issue requires demonstration of long-term core cooling to meet 10 CFR 50.46 requirements and also 10 CFR 100 or 50.67 dose requirements. The 50.46 compliance requires determination of the inventory loss (i.e., evaluation of long-term core cooling) and is evaluated in Appendix E. The dose consequence requires evaluation of the dose source term in the primary-to-secondary leakage that is predicted. The dose is directly related to the SGTR leakage rate and RCS fluid activity including any contribution from the fuel and gap gases in the event that the fuel pin cladding ruptures as a result of the LOCA in the hot leg U-bend. Cladding rupture is less likely for these hot leg U-bend LOCA scenarios that have the greatest potential to cause a SGTR, because cold BWST temperatures with all the ECCS available is used to maximize the cooling of the steam generator tubes to create consequential SGTRs. When the cladding remains intact, the dose source terms are limited to the RCS activity that existed prior to the accident and the RCS leakage rate based on the number of severed tubes and the differential pressure. As shown in Section E.2.4 of Appendix E, the probability for a single tube is 0.041 and the probability of four severed tubes is less than 10^{-6}. Nonetheless, this evaluation was performed with the conservative assumption of four severed tubes. While multiple tubes may be postulated to fail as a consequence of the LOCA cooldown, the leakage rate is less than that for the non-LOCA induced single tube SGTR scenario because of the large primary-to-secondary pressure differentials that exist for that transient. In addition, if consequential SGTRs are predicted during the refill of the HL LOCA scenario, they occur when the secondary side pressure is near the atmospheric pressure range. There is no steaming in the secondary side at this time or EFW flow from a turbine driven pump. Therefore, there are effectively no airborne releases from the HL LOCA event with consequential SGTRs.

This appendix summarizes the current B&W-designed plant licensing basis, discusses the regulatory dose requirements, and describes the analyses that demonstrate the cladding integrity is maintained for the hot leg U-bend LOCA that leads to consequential SGTR. Adequate long-term core cooling, limited primary-to-secondary leakage rates, and analyses that show the fuel pin cladding does not rupture, ensure that the radioactive release for the postulated hot leg LOCA is bounded by the current SGTR doses and well bounded by MHA(Maximum Hypothetical Accident).

F.2 Current Licensing Basis for Dose Consequences of LOCA and SGTR

In addition to the spectrum of LOCA break sizes and locations that satisfy the requirements of 10 CFR 50.46, the B&W plant licensing bases include dose consequences of LOCAs of various sizes and at various locations. The LOCAs analyzed for dose consequences range from a DEG (Double-Ended Guillotine) large break to a CRE (Control Rod Ejection) small break. The DEG break could occur anywhere in the RCS piping, and the CRE occurs in the reactor vessel head. The source term assumed for the CRE is commensurate with the amount of fuel expected to fail during the event. The

DEG source term in at least one of the licensee's documentation conservatively assumes a source term of the gap material for the entire core. The SGTR analyses conservatively assume RCS activity based on continuous plant operation with 1% failed fuel. The RCS activity corresponding to 1% failed fuel will be significantly lower than the RCS activity allowed by the plant Technical Specifications which protects the public from receiving a dose equivalent to a small fraction of 10 CFR 100 or 50.67 limits.

The B&W plant licensing bases also include a dose using the MHA source term. The MHA source term is based on TID-14844 [F-4]. The MHA evaluations assume that 100% of noble gases, 50% of iodine and 1% of solids of the core activity is released to the containment during the accident. Half of the iodine released to the accident will be plated out on the surfaces and 25% of core iodine activity will be available for release from the containment. The stated purpose of the MHA is to calculate a dose larger than any that could occur (bound any accident) so that it can be used to establish the exclusion area boundary of the plant in order to conservatively protect the public.

The current licensing basis of the B&W plants assumes a constant break flow rate for the SGTR of approximately 435 gpm from one SG tube. As summarized in Table E-3 of Appendix E for a bounding assumption of 4 severed tubes, a maximum leakage of 31 ft^3/min (232gpm) is postulated to occur. In addition, the reactor trip for the SGTR is assumed to cause at least one of the MSSVs to open, thus allowing fission products a direct path to the atmosphere for a short time in the licensing basis evaluations. For the postulated tube severs due to a break in the HL, the secondary pressure will not be sufficient to open the lowest setpoint MSSV during the period of time after the SGTR occurs. Therefore, the current licensing basis assumptions are bounding with respect to the conditions postulated for tube severs due to a break in the HL.

F.3 Regulatory Requirements

10 CFR 100.11 addresses the MHA source term that should be assumed in establishing the site radiological boundaries. Footnote 1 of that regulation is reproduced below:

> "[1] The fission product release assumed for these calculations should be based upon a major accident, hypothesized for purposes of site analysis or postulated from considerations of possible accidental events, that would result in potential hazards not exceeded by those from any accident considered credible. Such accidents have generally been assumed to result in substantial meltdown of the core with subsequent release of appreciable quantities of fission products."

For plants that have incorporated AST (Alternate Source Term) methodology into the plant licensing basis, paragraph 2.1 of Regulatory Guide 1.183 offers this guidance:

> "The AST must be based on major accidents, hypothesized for the purposes of design analyses or consideration of possible accidental events, that could result in hazards not exceeded by those from other accidents considered credible. The AST must address events that involve a substantial meltdown of the core with the subsequent release of appreciable quantities of fission products."

The common thread is that the consequences are limited to a "credible event." If any one of these fission product barriers (fuel cladding, RCS, containment) is maintained, no added dose consequences due to an accident will be realized and therefore do not need to be considered.

F.4 Cladding Rupture Study

Analyses were performed to determine the likelihood of cladding rupture during the blowdown or core reflooding period for a hot leg U-bend break. The model developed in Appendix A to determine the SG tube loads was used as the basis for this analysis. However, the inputs to these analyses were modified to maximize the likelihood of cladding rupture. If rupture is not predicted with the modified inputs, then rupture will not occur coincident with a LOCA induced SGTR. If the fuel cladding remains intact for this event, a source term equivalent to that assumed for the MHA as discussed in Section F.2 and F.3 is not credible and therefore should not be considered. Instead, the dose consequences are due to RCS activity only.

F.4.1. Technical Background

The break scenarios that create the large SG tube loads are upper hot leg breaks. These breaks maintain a positive core flow during blowdown (i.e. from the core inlet to the core exit). Liquid from the cold legs and reactor vessel downcomer regions (including ECCS when available) must pass through the core as it flows toward the break. As a result, the lower portions of the core can remain in a pre-CHF (critical heat flux) heat transfer mode with effectively subcooled or saturated nucleate boiling for up to five or ten seconds longer than the core exit. The effectiveness of the core cooling in the middle and lower regions of the core means that the fuel temperatures are lowered during the initial portion of the blowdown transient. As the blowdown transient evolves, the liquid flowing up the core saturates and boils, cooling the core exit cladding with steam and liquid droplets to enhance the post-CHF heat transfer in the upper core regions. During the middle of the blowdown phase, the core heat addition and continued flashing from the RCS pressure decline result in complete voiding in the core. The steam cooling is able to remove only a small portion of the core decay heat and the cladding can heat up. This heat up is typically halted after the core flood tanks (CFTs) begin to discharge and fill the lower plenum of the reactor vessel. Near the end of blowdown the lower plenum is filled from the CFT liquid and the core refill and reflood phase is initiated. The quench front progresses from the bottom to the top of the core, which quickly quenches the cladding in the lower portion of the core. The upper portion of the core is cooled with high velocity steam and liquid droplets entrained in the steam, but this heat removal is much less effective than the heat removal in the lower core from the advancing quench front. Eventually the pumped ECCS injection from the LPI and HPI will activate and complete the core reflooding and quench the entire core.

From the above discussion, it is clear that the core cooling challenges are the greatest in the upper core region. During the early portion of blowdown, these challenges come from departure from nucleate boiling (DNB) timing. During the later stages of blowdown, these challenges come from the mechanics of the reflooding process. If the core power is peaked near the core exit, the initial CHF margin is minimized such that the cladding will experience DNB very early in the transient. Further, the lower power at the core inlet associated with a core exit peaked power shape does not promote as much boiling, which decreases the core exit steam velocity and amount of liquid entrained in the steam. Consequently, the potential for cladding rupture is maximized for axial peaks skewed to the core exit. Therefore, the studies performed to assess the likelihood of cladding rupture following a hot leg break used core exit skewed power peaks.

F.4.2. General Analysis Approach

The cold leg pump discharge (CLPD) LOCA linear heat rate (LHR) limit analyses establish the maximum core peaking limits by considering five power shapes with axial peaks at the mid-span between the spacer grids using the BWNT LOCA Evaluation Model (BAW-10192P-A - [F-1]). These analyses are performed using conservative inputs protected by plant Technical Specification limits and methods imposed by 10 CFR 50.46 and Appendix K to maximize the calculated peak cladding temperature (PCT). The hot leg LOCA cladding rupture study used the same conservative methods to minimize the core heat removal and maximize the likelihood of cladding rupture.

The previous LOCA analyses performed to predict the maximum tube loads for BAW-2374 (Appendix A) did not assume a loss of offsite power (LOOP) or single failure that prevented any ECCS equipment from providing flow to the RCS. The result was a rapidly cooled core that did not predict cladding rupture. For this cladding rupture study, reduced ECCS could potentially delay core cooling and maximize the likelihood of cladding rupture. Therefore, the flow from only one LPI pump without credit for HPI flow was simulated as added conservatism in the cladding rupture studies. Although this is conservative in the longer term portion of the analysis, the greatest challenge to cladding rupture is while the CFT is flowing and this occurs before the pumped injection begins. Therefore, the CFT initial inputs were set to delay the timing of the injection and to minimize the injection rate during the draining period (i.e. minimize cover gas pressure and maximize initial level). Postulating a loss-of-offsite power (LOOP) trips the reactor coolant pumps (RCPs), reduces the core flows and hastens DNB. Therefore, a LOOP was modeled at the time of break opening for this analysis.

The clad rupture status is also dependent upon the plant design (raised loop vs lowered loop), fuel type, cladding material used (zircaloy or M5), LHR limit (fuel and plant specific), and time in life (TIL). Section F.4.3 discusses the basis for the plant type, fuel design, cladding material, and LHR limit selected for analyses. The time in life was considered in a single analysis by adding additional hot pins that simulate all times in life to evaluate the increased potential for cladding rupture due to elevated fuel pin internal rod pressures calculated by the NRC-approved TACO3 code [F-2].

F.4.3. Plant Type Specific Analyses

The cladding rupture study is a generic B&W task that can be used for all of the B&W-designed plants. Among these plants, there are two distinct plant designs and at least four different fuel types used in the most recent fuel reloads. Further, each plant has different LOCA linear heat rate (LHR) limits based on the fuel type, ECCS capabilities, and EM methods used for the analyses. The challenge is to select a plant and fuel type to perform an analysis that is generically applicable to every plant for the hot leg LOCA cladding rupture study.

The biggest difference in the two B&W plant designs is the loop orientation (raised versus lowered) and number of internals reactor vessel vent valves (RVVVs, four versus eight). These differences influence the core cooling characteristics as dictated by the flow paths (i.e. through the RVVVs or RCS loops) that are established to transfer the core heat to the containment for CLPD breaks and result in variations of the calculated LHR limits. The hot leg is the primary flow path that removes the core generated heat for the hot leg LOCA. Since the hot leg geometry is similar for the two plant types, less variation in the LOCA results are expected for the hot leg breaks. Nonetheless, two separate analyses were performed, one bounding the Lowered Loop (LL) plants and one for the Raised Loop (RL) plant.

F.4.3.1. 177-FA Lowered-Loop Plants

There are six B&W plants that have similar lowered-loop (LL) RCS designs. The major differences between each LL plant that affect SG tube load analyses include fuel type, CHF correlation, analyzed core power, internal fuel pin pressure, and peak LHR limit. Any structural and operational plant differences are considered insignificant for this cladding rupture study and were input consistent with the final plant design model chosen. Table F-1 tabulates the desired inputs for the B&W 177-FA LL plant hot leg break cladding rupture study as developed in the following paragraphs.

The cladding temperature response and the potential to rupture cladding following a hot leg break are dependent on the core stored energy, DNB margin, core power level, and fuel assembly design. Based on a review of the various parameters used in the LL plant LOCA LHR limit analysis, it was concluded that the CR-3 system model with Mark-B-HTP fuel at 2568 MWt with a 10-ft peak LHR of 17.0 kW/ft was a reasonable generic choice that should bound all the LL plants for this fuel pin rupture study. This fuel design has the lowest CHF and highest LHR limit at the highest middle-of-life (MOL) burnup of 45 GWd/mtU. This case should also provide a reasonable bound that should remain representative of future fuel designs barring a revolutionary change. This model was analyzed with the hot pin methods in order to evaluate all times in life.

The combination of the initial cover gas pressure and liquid volume within the CFT can result in different CFT flow rates, which lead to variations in cladding temperature responses for LOCA events. The combinations of minimum cover gas pressure and maximum liquid volume results in the longest time before the CFTs begin injecting and the slowest injection rate once they begin to inject. Because cladding rupture is expected to occur early in the event, this combination will maximize the likelihood of cladding rupture. The selection of CFT liquid temperature is not a critical parameter for the clad rupture study. It is clearly conservative to use a low temperature for SG tube loads. Hotter injected liquid is conservative for CLPD LOCA core cooling calculations because it reduces the condensation during the later blowdown period which reduces the negative core flow velocities that provide cooling after the CFTs begin to discharge. The hot leg break core flows remain positive for the entire transient, so the CFT condensation is less important. If the temperature is lower, the core flows could be less positive, however, the additional condensation would shorten the lower plenum refill time and initiate core reflood sooner. Because of these competing effects, a CFT temperature in the nominal range is selected. Based on an informal set of plant data, the containment temperatures can be in the 110 to 115 F range for some of the southern plants and as low at 85 to 90 F for some of the northern plants. Therefore a value of 100 F was assumed for this analysis based on an average of the data that was readily available.

The temperature of the ECCS liquid plays a minor role in determining the cladding temperature response. Higher temperatures are slightly more conservative for CLPD breaks but could result in more boiling during the reflood period and faster core reflood initially that could lower the probability of cladding rupture for a hot leg break. However, the SG tube-to-shell temperature differential is maximized by considering the coldest ECCS temperatures. If a maximum ECCS temperature were considered, the results of the tube load analysis would be significantly better. Based on an informal set of plant data, the BWST temperatures can be in the 70 to 90 F range for some of the southern plants and as low as 50 to 80 F for some of the northern plants. Therefore a reasonable nominal value of 70 F was assumed for this analysis based on an average of the data that was readily available. This value is also a reasonable nominal value based on Tech Spec BWST temperature ranges for the plants.

The 177-FA LL hot leg break analysis rapidly depressurizes the RCS and the fluid in the upper core region saturates almost immediately. The flashing in the upper core regions increases the voiding and results in DNB for cladding in the high power regions within roughly one second after break opening as shown in Figure F-1. The cladding temperatures rapidly increase as the film and transition boiling cannot remove the heat generated in the pin. The cladding temperatures in the upper core region heatup to approximately 1200 F in the 2 to 3 second time period as the core flow decreases and the core voiding increases. The fuel temperatures continuously decrease as the core power declines from the reactor shutdown from the moderator density feedback. The CFT flow initiates as the RCS depressurizes below the CFT fill pressure and it begins to refill the downcomer and lower plenum with some flow reaching the core by roughly 12 seconds. These core flow surges enhance core cooling and reduced the cladding temperature by approximately 200 F over the next several seconds. The core flows stagnate between 13 and 14 seconds as the lower plenum refills and the cladding begins to heat up again.

The RCS break flows subside as end of blowdown approaches near 14 seconds into the transient. As the RCS and core flows decline, the hot pin temperatures slowly heat up and approach the peak value of 1341 F at 18.7 seconds. At this time the lower portions of the core have refilled and begun to quench. The steam production at the quench front entrains liquid droplets that are able to exceed the fuel pellet heat production rate. From this time on, the steam and liquid droplet carryout from the quench front propagation remove the core decay heat and metal water reaction energy generated in the upper regions of the core and limit the PCT to a maximum at the time of bottom of core recovering.

The key to this study is maintaining a margin between the cladding temperature and the rupture temperature. The minimum difference in the cladding temperature and the rupture temperature for the hottest segment in the hot channel was calculated for the various hot pins simulated in the analysis and they are shown in Figure F-2. The beginning-of-life (BOL) pin had the lowest initial pin pressure and that results in the lowest hoop stress for any other TIL condition. Lower hoop stresses increase the rupture temperature and produce more margin to rupture than the middle of life cases.

The MOL pin had the lowest PCT for all the hot pins, but it had a higher hoop stress that reduced the rupture temperature and it predicted a margin to rupture of ~118 F. The MOL pin with the artificially increased pin pressure had the lowest rupture temperature and smallest margin to rupture of approximately 93 F. An end-of-life (EOL) pin was not simulated in the analysis because the LHR is reduced to limit the maximum internal rod pressure. The reduction in the LHR reduces the fuel temperatures such that the rupture margin predicted by the MOL pin with the elevated pin pressure bounds the EOL pins at their allowed peaking.

F4.3.2. 177-FA Raised-Loop Plants

Davis Besse is the only B&W-designed RL plant. During the course of this analysis, it was concluded that the lowered-loop plant cladding rupture results could not be used to bound the raised-loop plant without some additional plant-specific analyses. Table F-2 tabulates the desired inputs for the B&W 177-FA RL plant hot leg break cladding rupture study as developed in the following paragraphs.

The cladding temperature response and the potential to rupture cladding following a hot leg break are dependent on the core stored energy, DNB margin, core power level, and fuel assembly design. The Mark-B10K fuel at 3025 MWt with a 10-ft peak LHR of 15.7 kW/ft at 35 GWd/mtU was used in the analysis. For these analyses, the RELAP5/MOD2-B&W [F-3] hot pin EM method was used with multiple hot pins, consistent with the approach used for the LL analysis. Based on the discussions from Section F.4.3.1, a reasonable nominal CFT temperature of 100 F was assumed for this analysis. An average of the Tech Spec minimum (35 F) and maximum (90 F) BWST temperatures was used in the analysis.

The results of the 177-FA RL hot leg break analysis were similar to the LL analyses in that after the opens the RCS rapidly depressurizes and the fluid in the upper core regions saturates almost immediately. The flashing in the upper core regions increases the voiding and results in DNB for cladding in the high power regions within roughly one second after break opening as shown in Figure F-3. The cladding temperatures rapidly increase as the film and transition boiling cannot remove the heat generated in the pin and convected to the cladding by the gap heat transfer.

The cladding temperatures in the upper core region heatup to almost 1100 F in the 2 to 3 second time period as the core flow decreases from the core voiding. The fuel temperatures continuously decrease as the core power declines from the reactor shutdown from the moderator density feedback. The downcomer flashing around 3 seconds resulting in a substantial core flow surge that improved the cladding heat removal and decreased the cladding temperatures by 100 to 200 F in several seconds. The flow surge subsided in the five second time period and the cladding again began a slower heat up. The rate of heat up increases between 8 and 9 seconds because condensation on the CFT liquid injection reduced the magnitude of the positive core flow rates. The CFT flow refilled the downcomer and some small flow from this liquid and condensate reached the core at roughly 16 seconds.

The RCS break flows subside near 13 seconds as end of blowdown approached. As the RCS and core flows declined, the hot pin temperatures reached the peak value of 1322 F at 15.9 seconds. The lower portion of the core began to quench between 18 and 19 seconds and the steam production at the quench front entrained liquid droplets and carried them upward while cooling the cladding and fuel pellets in the upper regions of the core. From this time on, the steam and liquid droplet carryout from the quench front propagation removed the core decay heat and metal water reaction energy generated in the upper regions of the core and continuously reduced the cladding temperatures until they were quenched by the rising mixture level.

The margin to rupture for each of the hot pins modeled was calculated as a function of time for the highest temperature segments in each channel and they are shown in Figure F-4. The BOL pin has the lowest pin pressure and that results in the lowest hoop stress for any other TIL condition. Lower hoop stresses increase the rupture temperature and provide substantially more margin to rupture than the middle of life cases. The MOL pin had the lowest PCT for all the hot pins with a margin to rupture of ~120 F. The increased pin pressure MOL pin had the highest hoop stress and lowest rupture temperature that generated the smallest margin to rupture of approximately 72 F. An EOL pin was not simulated in the analysis because the LHR is reduced to limit the maximum internal rod pressure. The reduction in the LHR reduces the fuel temperatures such that the rupture margin predicted by the MOL pin with the elevated pin pressure bounds the EOL pins at their allowed peaking.

The results of this study for the 177-FA RL are similar to the results predicted with the 177-FA LL plant. Slight variations in the event timing are noted due to the variation in the number of vent valves and the ECCS boundary conditions (CFT cover gas pressure and liquid temperature and ECCS liquid temperature).

F.5 Conclusion

The conclusion of the cladding rupture study is that the cladding integrity is not compromised during the blowdown, refill, or reflood phase of the hot leg break event that produces the most limiting SG tube-to-shell temperature differential for either type of B&W plant (i.e., LL and RL). The cladding rupture analyses used conservative methodology and nominal, to conservative, input assumptions. Without the breach of the fuel cladding or failure of the ECCS during the long-term core cooling, no large source term exists, and the radiation release is due to the radioactive products contained in the coolant and not the fissionable material or gap activity within the fuel itself. With respect to 10 CFR 100 implied requirements, the assumption of the use of an MHA source term for this event is not credible, and therefore a realistically bounding source term no worse than that which could exist for normal operation should be used. The most common conservative assumption for source term in the non-LOCA SGTR event is the RCS activity with 1% failed fuel during power operation. The RCS activity corresponding to

1% failed fuel is significantly higher than the RCS activity allowed by the plant Technical Specifications.

For the non-LOCA SGTR event at power, the leaking RCS fluid will flash into steam, thereby carrying the volatile compounds into the steam. The activity in the steam will be released via MSSVs at the time of plant trip and later via the condenser air exhaust system. In the case of postulated SG tube failures following LOCA, the temperature of the leaking fluid will be always less than 200 F. This is because the RCS fluid leaking via steam generator tubes is the water from directly from the BWST or the recirculating ECCS fluid cooled by the DHR heat exchangers. Therefore the leaking fluid will not flash into steam. The activity will remain in the water and will be confined to the secondary side of the steam generator. Further, since the RCS will be diluted with the ECCS fluid during the LOCA, the activity in the leaking fluid will be significantly lower than the RCS activity prior to the postulated LOCA. Also, the operators will isolate the affected steam generator to preserve the NPSH during the LOCA; therefore the possibility of radiation releases to the environment is very limited.

It is concluded based on the discussions provided that the existing dose consequences contained in the licensing bases of the B&W plants remain bounding for this LOCA scenario with consequential SGTRs. The dose consequences of the LBLOCA at the top of the candy-cane, with four ruptured tubes, are bounded by the non-LOCA SGTR event because the fuel pin cladding integrity is maintained.

F.6 References

F-1. AREVA Proprietary Topical Report BAW-10192P-A, Rev. 0, "BWNT LOCA – BWNT Loss-of-Coolant Accident Evaluation Model for Once-Through Steam Generator Plants", June 1998.

F-2. AREVA Proprietary Topical Report BAW-10162P-A, Rev. 0, "TACO3 – Fuel Pin Thermal Analysis Code", October 1989.

F-3. AREVA Proprietary Topical Report BAW-10164P-A, Rev. 4, "RELAP5/MOD2-B&W – An Advanced Computer Program for Light Water Reactor LOCA and Non-LOCA Transient Analysis", November 2002.

F-4. J.J. DiNunno et al., Technical Information Document (TID)-14844, « Calculation of Distance Factors for Power and Test Reactor Sites, » U. S. Atomic Energy Commission (now USNRC), 1962.

Figure F-1. 177-FA LL Plant Fuel Pin and Rupture Temperatures

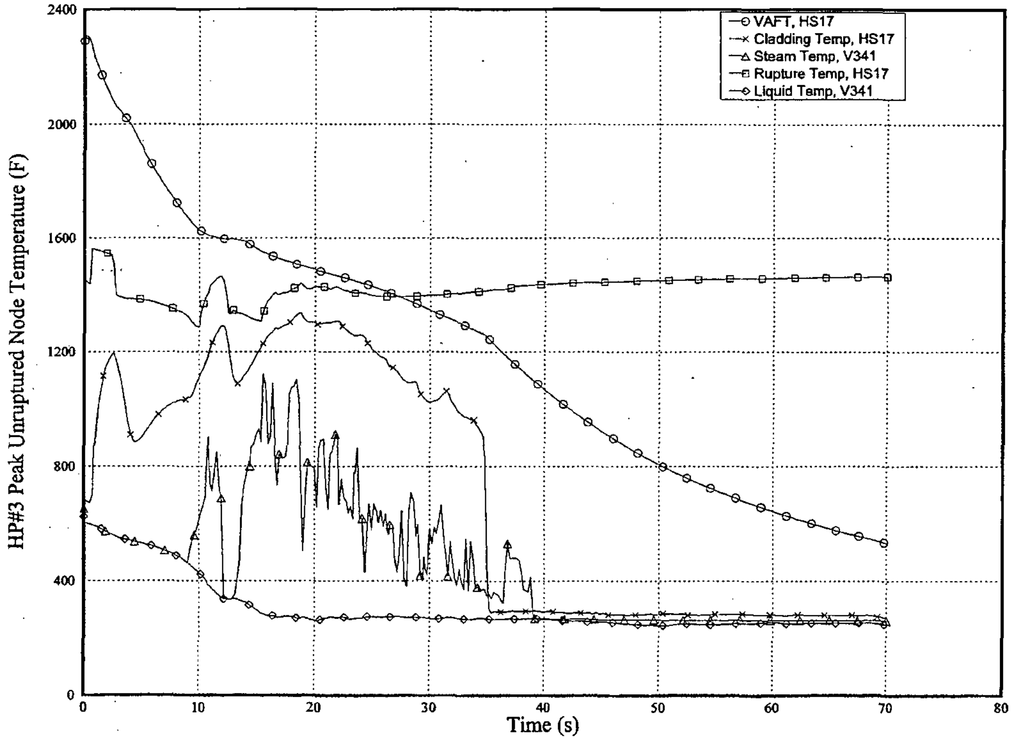


Figure F-2. 177-FA LL Plant Margin to Cladding Rupture

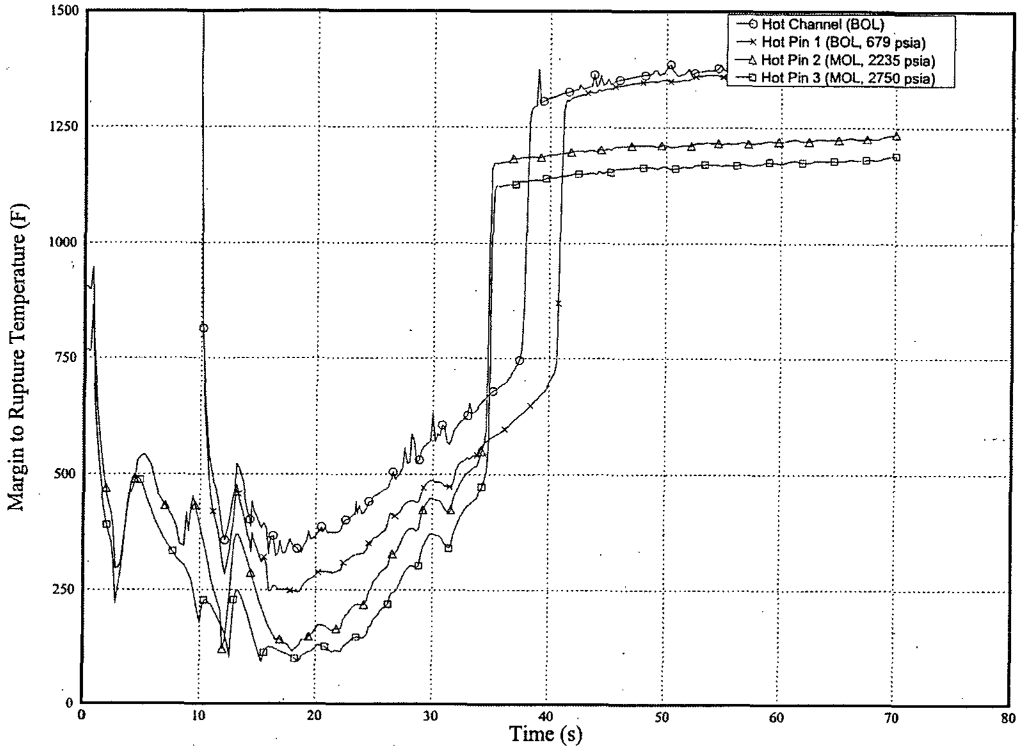


Figure F-3. 177-FA RL Plant Fuel Pin and Rupture Temperatures

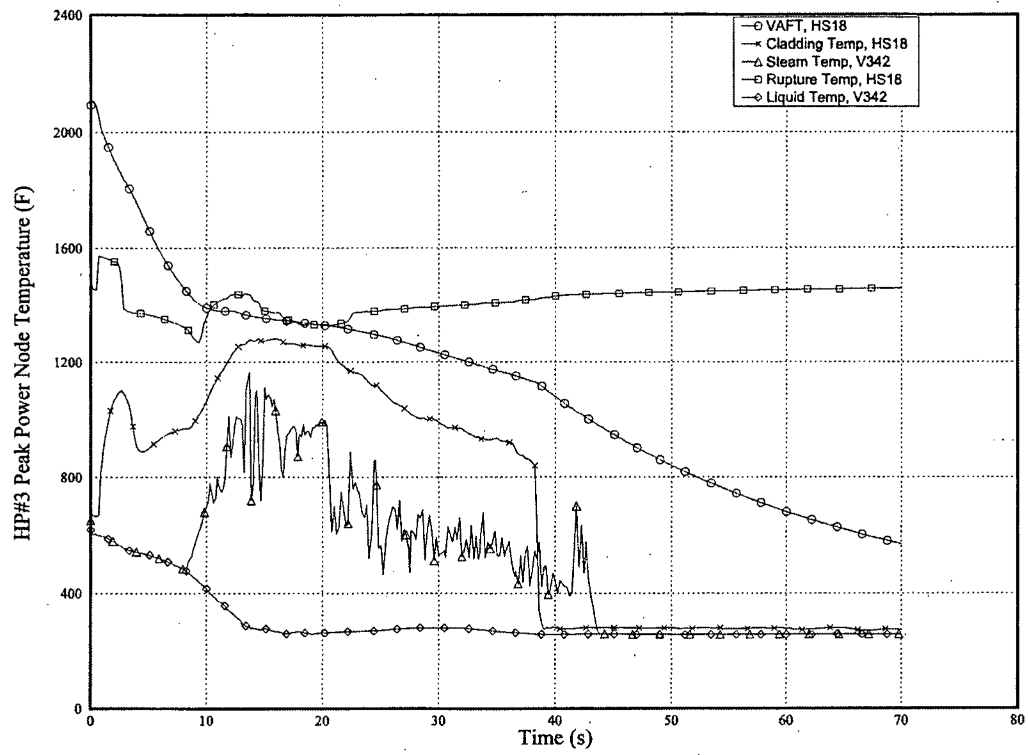


Figure F-4. 177-FA RL Plant Margin to Cladding Rupture

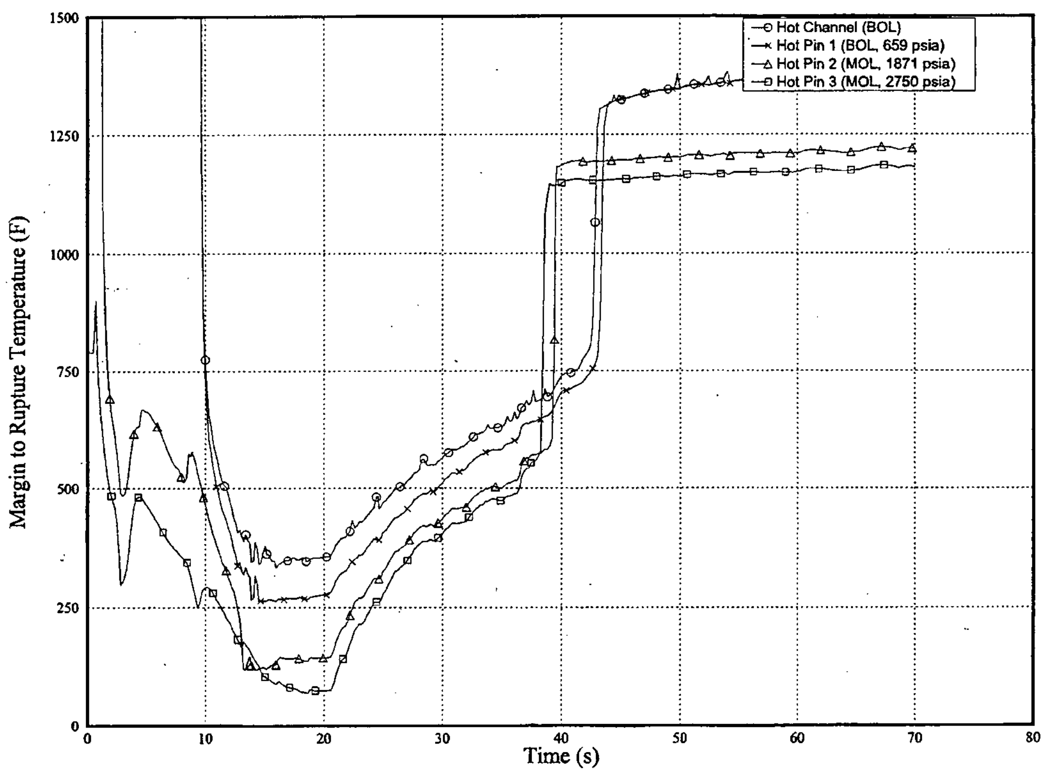


Table F-1. B&W 177-FA LL Initial & Boundary Conditions for Cladding Rupture Study

Parameter	Value
Analyzed Core Power Level (MWt)	2619.36 (1.02 * 2568)
Decay Heat	1.2 * ANS 71 + B&W Heavy Actinides
Fuel Type	Mark-B-HTP
CHF Correlation	BHTP
Peak Axial Power Elevation (ft)	9.536
Peak LHR @ Peak Power Elevation (KW/ft)	17.0
Largest TIL at Peak LHR (GWd/mtU)	45
CFT Initial Volume (ft^3)	1110
CFT Initial Cover Gas Pressure (psia)	565
CFT Temperature (F)	100
CFT Surge Line FLC	7.0
ECCS Liquid Temperature (F) {from BWST}	70
Single Failure for Cladding Rupture Studies	One ECCS train
Offsite Power	LOOP @ Turbine Trip (1)

Notes:

1. Turbine trip is conservatively modeled as coincident with break opening.

Table F-2. B&W 177-FA RL Initial & Boundary Conditions for Cladding Rupture Study

Parameter	Value
Analyzed Core Power Level (MWt)	3025.32 (1.02 * 2966 MWt)
Decay Heat	1.2 * ANS 71 + B&W Heavy Actinides
Fuel Type	Mark-B10K
CHF Correlation	BWC
Peak Axial Power Elevation (ft)	9.536
Peak LHR @ Peak Power Elevation (KW/ft)	15.7
Largest TIL at Peak LHR (GWd/mtU)	35
CFT Initial Volume (ft^3)	1080
CFT Initial Cover Gas Pressure (psia)	582
CFT Temperature (F)	100
CFT Surge Line FLC	7.0
ECCS Liquid Temperature (F) {from BWST}	62.5
Single Failure for Cladding Rupture Studies	One ECCS train
Offsite Power	LOOP @ Turbine Trip (1)

Notes:

1. Turbine trip is conservatively modeled as coincident with break opening.

Appendix G

Summary of Future Commitments

Note: Appendix G was added in Revision 2 of BAW-2374, however, no margin bars are shown.

Appendix G Table of Contents

Appendix G List of Figures

G.1. Summary of Future Commitments

This Appendix was added to summarize the commitments that have been made to ensure the analyses performed and conclusions developed in this Topical Report remain applicable.

1. If significant changes are made to the plant (i.e. fuel designs, ECCS flow rates, or Evaluation Model methods used to perform LOCA analyses for the B&W-designed plants referencing this Topical Report), the utilities must evaluate the potential for fuel pin cladding rupture for a double-ended guillotine hot leg break that could result in consequential SGTRs.

2. The utilities referencing this Topical Report will evaluate the potential leakage rates based on the calculations in Appendix E from as-found SG tube flaws following each outage in which steam generator tube examinations are conducted. These evaluations will be based on the full area double-ended guillotine hot leg U-bend LOCA tube loads from full power operation. The cumulative leakage from free span and tube end flaws (i.e. cracks within the tubesheet) plus the leakage occurring at tube repair products (e.g. plugs, repair rolls, etc.) must be less than that calculated from an 0.014 ft^2 leakage area (this area is slightly greater than that of four double-ended tube severs) used in the Appendix E analyses.

The utilities are responsible for ensuring that these requirements are met and can work with the NRC to define the method of communicating the compliance to these commitments. These may be accomplished via several options such as a Licensing Commitment, Technical Specification Amendment, or any other means that is acceptable to the parties involved based on the general information provided in this appendix.

G.2. Method to Validate the Leakage Rate Criteria

After BAW-2374 is approved, the hot leg LOCA supplemental leakage evaluation will be performed by validating that the as-found flaws will not result in the integrated leakage contributions greater than the flow rates, given in Table E-3 of Appendix E, that were used in the plant-specific NPSH analyses. Validation of the leakage rates can be made in one of two different ways using either a conservative tube load limited to the yield strength of the tubing applied to all the tube flaws, or tube location-specific loads determined based upon the flawed tube radial location within the SG. The two methods of validating the leakage are based on either leakage area or leakage rate as follows:

A. The simplest method is to demonstrate the cumulative leakage area is less than the 0.014 ft^2 used in Appendix E calculations. The total leakage area from all free span flaws that could propagate through-wall or sever from the LBLOCA thermal loads is added to the other effective leakage areas. These other effective leakage areas are made up of the minimum of the flaw area or smallest annular flow gap area inside the tube crevice from flaws within the tubesheets plus the effective area associated with leakage from all tube repair products.

B. The most rigorous method is to calculate the total leakage rate based on the cumulative leakage area with adjustments to the tube rupture pressure differences from the plant-specific steam line geometry, containment differences, or different ECCS flow rates. This analysis could also include the elevation head differences associated with the specific flaw locations.

The simplest validation of the leakage is based on the cumulative leakage area. The total leakage area will be determined based on the as-found flaw distribution using one of the following methods. The total leakage area being less than or equal to 0.014 ft^2 is confirmed by meeting any of the following conditions for the as-found population of circumferential degradation sites.

1. There are four or less tubes with free span circumferential degradation. This would include consideration of an effective number of free span tube failures based on flaws that could propagate through-wall inside the tube sheet.

2. There are 40 or less tubes with free span circumferential degradation located outside a tubesheet radius of 35 inches and the measured distributions of maximum depths and circumferential lengths of the upper 50 percent of the cumulative distribution functions are to the left (less severe) of Figures G-1 and G-2. (These curves represent the effective distributions used in the analysis of Appendix E, Figures E-6 and E-7.)

3. There are four or less tubes above the lower line of the leak/sever plot of Figure G-3. This plot is based on the assumption of maximum possible tube load (yield strength of the tubing), a maximum depth NDE sizing uncertainty (standard deviation) of 18.22 %TW and a circumferential length NDE sizing uncertainty (standard deviation) of 0.1 inches. Four tube indications that lie just on the leak/sever line leads to a probability of 0.001 that four or more tubes will leak or sever at worst case postulated LBLOCA conditions.

4. If the above conditions are not met, the probability of a total leakage area of 0.014 ft^2 will be calculated based on the NDE measured maximum depths and circumferential lengths of the as-found population of flaws. Sizing, material property and tube sever equation uncertainties will be included. Tube loads will be adjusted only if the assumption of maximum possible axial loads for all degraded tubes proves untenable. Acceptable LBLOCA leakage integrity is demonstrated if the probability of exceeding a leakage area of 0.014 ft^2 is less than 0.01. All degradation locations will be considered including tubesheet crevice sites.

(Note that NDE sizing uncertainties and material property parameters may require adjustment to plant specific conditions and inspection practices.)

If the leak area method does not conclude acceptable results, the more detailed leakage rate method can be used. With this method the plant specific steam line geometries, tube loads, flaw locations, and key LBLOCA flow boundary conditions will be used in a detailed analysis to show the plant specific LBLOCA integrated leak rates are less than the integrated leak rates, shown in Table E.3 of Appendix E. If the conclusions from this detailed method are unacceptable, the NRC will be notified in accordance with 10 CFR 50.72 and 50.73 prior to resumption of plant operation.

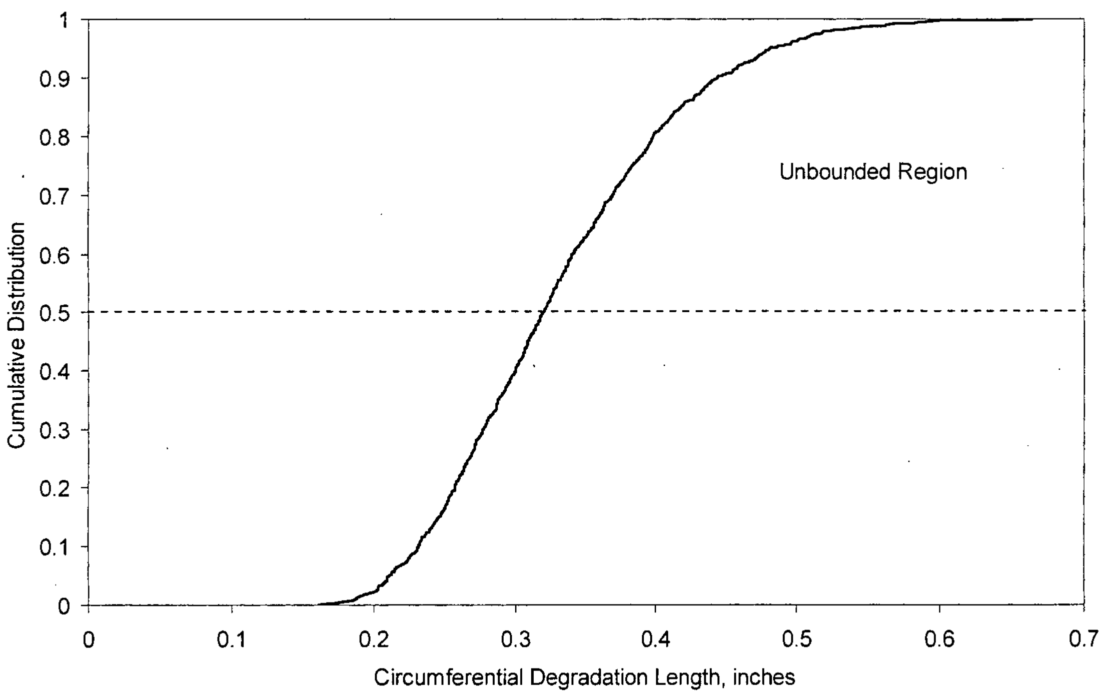


Figure G-1. EOC Length Distribution

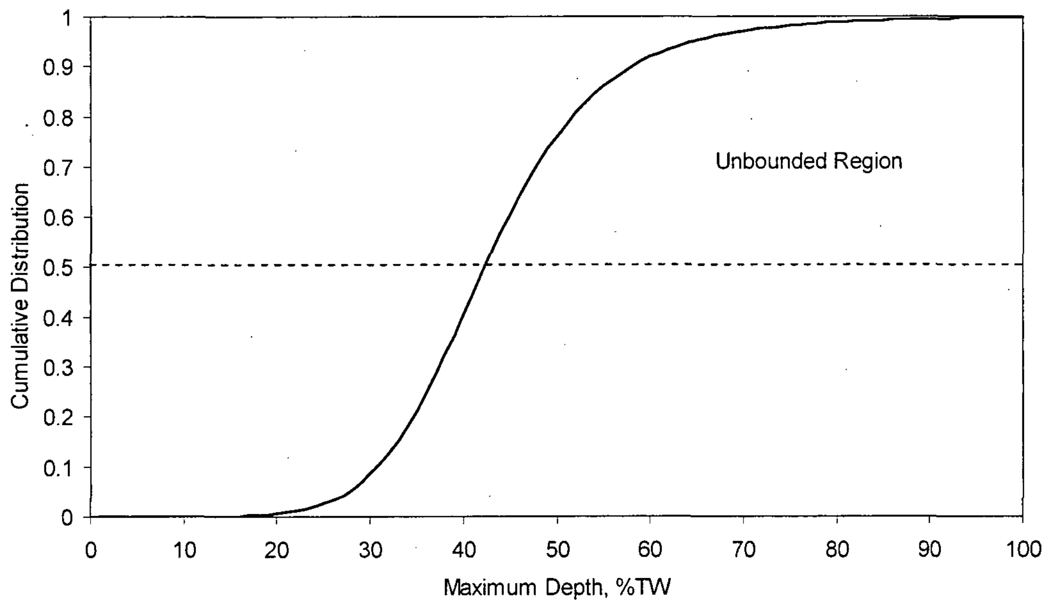


Figure G-2. EOC Maximum Depth Distribution

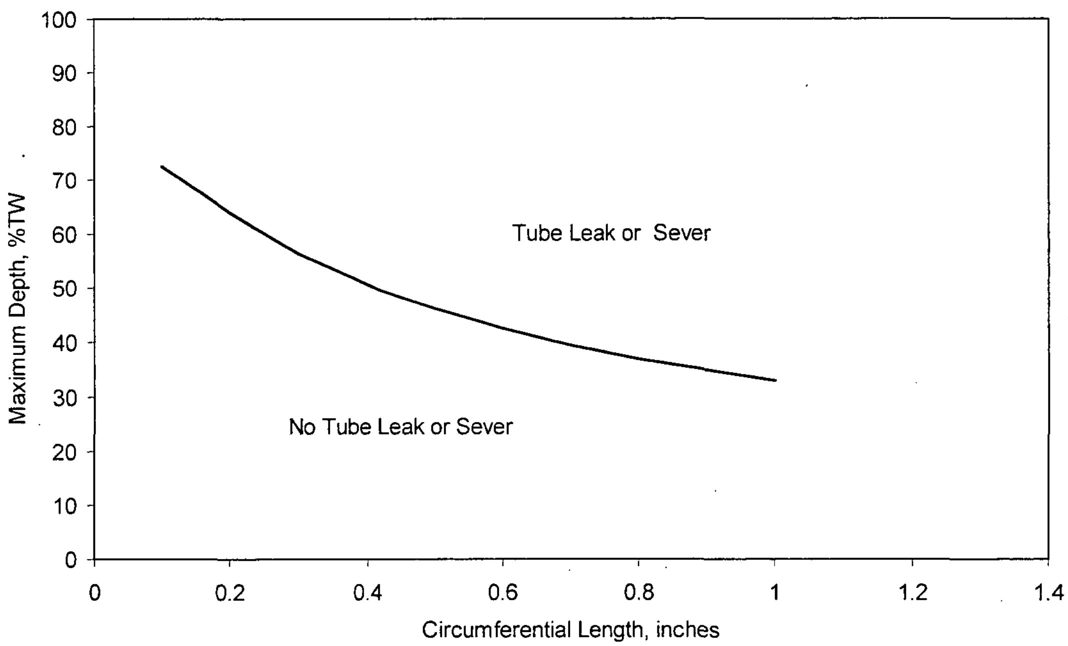


Figure G-3. Leak/Sever Condition Monitoring Plot

G.3 Technical Specification or Commitment Update Example

Following NRC approval of BAW-2374, the plant licensing basis will be changed. The preferred method for incorporating the change may vary from plant to plant. The material from Sections G.1 and G.2 contain the commitments and methods that need to be incorporated into the documentation and process for confirming applicability to the work described in this Topical Report.

The remainder of this section contains an example of how the Technical Specifications might be changed if this licensing change option was selected.

Note that "TSTF-449 type Tech Specs", versus "custom Tech Specs", were assumed for the following proposed sections/changes. (Most of the B&W-designed plants have already changed to TSTF-449 type Tech Specs, or they are in the process of changing their Tech Specs to TSTF-449 type Tech Specs.) There are three specific changes that are described.

CHANGE #1

Proposed "Generic" Addition to the "Provisions for SG Tube Repair Criteria" Section of the SG Tech Specs.

> **(X.) Based on the results of steam generator tube examinations performed during each inspection, a supplemental SG tube leakage evaluation based on hypothetical hot leg U-bend large break accident tube loads from BAW-2374, Rev _*(insert latest NRC-approved rev. number here)*__ shall be performed. The evaluation shall determine an expected, cumulative total SG tube effective leakage rate from tube degradation and other leakage from tube**

repair products (e.g. plugs, repair rolls, tube end cracking, wear dents, etc) based on the maximum hot leg pipe LOCA thermal tube loads. While the flawed tubes are plugged [or repaired], the total leakage from these as-found flaws should be less than that specified in Table E-3 of BAW-2374. In the event that the as-found tube flaws could have resulted in plant-specific leakage in excess of the Table E-3 values, the NRC will be notified in accordance with 10 CFR 50.72 and 50.73 prior to resumption of plant operation.

CHANGE #2

To the list of items required for your plant's inspection report, add:

(Y.) The results of the supplemental SG tube leakage evaluation based on a hypothetical hot leg U-bend large break accident described in BAW-2374.

CHANGE #3

<u>Proposed Revision to the "Accident-induced leakage performance criterion" definition in the Tech Specs.</u>

{Check the definition of your allowed leakage in your Tech Specs and update it if necessary to include the BAW-2374 scenario. Since the leak rate for the BAW-2374

scenario is greater than 1 gpm per SG, the plants need to make sure that the accident-induced leakage definition in their Tech Specs refers to a paragraph of their Tech Specs where CHANGE #1, above, appears. That is to say, the following paragraph currently has tube rupture as an exception. Since the hot leg pipe LBLOCA could result in consequential SGTR, the plants also need an exception for this accident (i.e., in addition to the tube rupture).}

(Z) **Accident induced leakage performance criterion: The primary-to-secondary accident induced leakage rate for any design basis accident, other than LBLOCA as defined in Section (*X above*) and a SG tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all SGs and leakage rate for an individual SG. Leakage is not to exceed 1 gpm per SG, except for specific types of degradation at specific locations as described in paragraph (*insert number*) of the Steam Generator Program. Limits for the accident leakage associated with the hot leg LBLOCA are provided in Section (*X above*).**

Appendix H

Glossary of Acronyms

Note: Appendix H was moved from Appendix E in Revision 1, however, no margin bars are shown.

ADV	Atmospheric Dump Valve
ANO	Arkansas Nuclear One
ASME	American Society of Mechanical Engineers
ARC	Alternative Repair Criteria
ASA	Automatic Submerged Arc
AST	Alternate Source Term
B&PV	(ASME) Boiler & Pressure Vessel (Code)
B&W	Babcock & Wilcox
B&WOG	Babcock & Wilcox Owners Group
BL	(NRC) Bulletin (Generic Communication)
BOP	Balance of Plant
BOL	Beginning of Life
BWST	Borated Water Storage Tank
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
CFT	Core Flood Tank
CHF	Critical Heat Flux
CL	Cold Leg
CLPD	Cold Leg Pump Discharge
CLPS	Cold Leg Pump Suction
CR	(NRC) Circular (Generic Communication)
CR-3	Crystal River Unit 3
CRE	Control Rod Ejection
DB	Davis Besse
DEG	Double-Ended Guillotine
DH	Decay Heat

DHDL	Decay Heat Drop Line
DNB	Departure from Nucleate Boiling
EAL	Emergency Action Level
ECCS	Emergency Core Cooling System
EFW	Emergency Feedwater
EFIC	Emergency Feedwater Initiation and Control
EFPYs	Effective Full Power Years
EM	Evaluation Model
EOC	End of Cycle
EOL	End of Life
EOP	Emergency Operating Procedure
EOTSG	Enhanced Once-Through Steam Generator
EPRI	Electric Power Research Institute
FA	Fuel Assembly
FTI	Framatome Technologies, Inc.
FSAR	Final Safety Analysis Report
GDC	General Design Criteria
GL	(NRC) Generic Letter (Generic Communication)
GLRP	Generic License Renewal Program
GOTHIC	Generation of Thermal-Hydraulic Information for Containment
GSI	Generic Safety Issue
HEP	Human Error Probability
HL	Hot Leg
HPI	High Pressure Injection
ID	Inner Diameter
IE	(NRC) Office of Inspection & Enforcement
IGA	Intergranular Attack

IN	(NRC) Information Notice (Generic Communication)
INEEL	Idaho National Engineering & Environmental Laboratory
ISI	Inservice Inspection
IST	Inservice Test
LBB	Leak-Before-Beak
LBLOCA	Large Break Loss-of-Coolant Accident
LERF	Large Early Release Frequency
LHR	Linear Heat Rate
LL	Lowered-Loop
LLNL	Lawrence Livermore National Laboratory
LOCA	Loss-of-Coolant Accident
LOOP	Loss of Offsite Power
LPI	Low Pressure Injection
LRF	Large Release Frequency
LTC	Long-Term Cooling
M&E	Mass and Energy
MFW	Main Feedwater
MHA	Maximum Hypothetical Accident
MOL	Middle of Life
MSIV	Main Steam Isolation Valve
MSLB	Main Steam Line Break
MSSV	Main Steam Safety Valve
MT	Magnetic Particle Testing
NDE	Non-Destructive Examination
NEI	Nuclear Energy Institute
NPRDS	Nuclear Plant Reliability Data System
NPS	Nominal Pipe Size

NPSH	Net Positive Suction Head
NRC	Nuclear Regulatory Commission
NUREG	NRC Report
OD	Outer Diameter
ONS-1	Oconee Nuclear Station-1
OTSG	Once-Through Steam Generator
PCT	Peak Cladding Temperature
PDA	Percent Degraded Area
PNNL	Pacific Northwest National Laboratory
POD	Probability of Detection
PRA	Probabilistic Risk Assessment
PT	Penetrant Testing
PWHT	Post-Weld Heat Treatment
PWR	Pressurized Water Reactor
PWROG	Pressurized Water Reactor Owners Group
PWSCC	Primary Water Stress Corrosion Cracking
QA	Quality Assurance
QC	Quality Control
QHO	Quantitative Health Objective
RB	Reactor Building
RC	Reactor Coolant
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RG	(NRC) Regulatory Guide
RL	Raised-Loop
ROTSG	Replacement Once-Through Steam Generator
RT	Radiographic Testing

RTE	Resistance Temperature Element
RV	Reactor Vessel
RVVV	Reactor Vessel Vent Valve
SAMG	Severe Accident Management Guidance
SBLOCA	Small Break Loss-of-Coolant Accident
SCC	Stress Corrosion Cracking
SCM	Subcooling Margin
SER	Safety Evaluation Report
SG	Steam Generator
SGTR	Stream Generator Tube Rupture
SKI	Swedish Nuclear Power Incorporate
SLLOCA	Surge-Line Loss-of-Coolant Accident
SSCs	Systems, Structures or Components
SMAW	Shielded Metal Arc Welding
TBV	Turbine Bypass Valve
TEC	Tube End Cracking
TIL	Time in Life
TMI-1	Three Mile Island-1
TSC	Technical Support Center
TSV	Turbine Stop Valve
TTS ΔT	Tube-to-Shell delta-Temperature
TW	Through-Wall
UFLTS	Upper Face of the Lower Tube Sheet
UT	Ultrasonic Testing