Duke Energy Corporation
Entergy Operations, Inc.
Florida Power Corporation

Oconee 1, 2, 3
ANO-1
Crystal River

The B&W Owners Group

AmerGen Energy Co., LLC.
FirstEnergy Nuclear Operating Co.
Framatome Technologies, Inc

TMI-1
Davis-Besse

Working Together to Economically Provide Reliable and Safe Electrical Power

Suite 525 • 1700 Rockville Pike • Rockville, MD 20852 • (301) 230-2100

July 7, 2000
OG-1792

Project No. 693

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

Subject: Submittal of Topical Report BAW-2374, "Justification for Not Including Postulated Breaks in Large-Bore Reactor Coolant System Piping in the Licensing Basis for Existing and Replacement Once-Through Steam Generators"

Gentlemen:

Enclosed are 15 copies of BAW-2374, which is submitted by the B&W Owners Group (B&WOG) for review and approval by the NRC. Three copies are being sent to the Document Control Desk and the remaining 12 copies to the NRC B&WOG Project Manager. This topical report presents the technical basis to support modifying the licensing basis for Babcock & Wilcox-designed nuclear power plants such that consideration of the effects of a break in large-bore reactor coolant system (RCS) piping is not required for once-through steam generator (OTSG) design and maintenance activities. The proposed change to the licensing basis is that the faulted loss of coolant accident (LOCA) OTSG licensing basis need not include the thermal and pressure loads from large-bore RCS pipe breaks in design and maintenance activities for existing and replacement OTSGs. The faulted OTSG condition for primary LOCA will include the dynamic and thermal-hydraulic loads from breaks in pipes that are attached to RCS large-bore pipes or components. The proposed exclusion of these thermal and pressure loads, along with the NRC-approved exclusion of the dynamic loads (BAW 1847), effectively removes LBLOCA from the design basis of all pressure boundary and non-pressure boundary parts associated with the OTSG.

The basis provided for the proposed change has been prepared in accordance with the guidance of Regulatory Guide 1.174. The attached B&WOG evaluation shows that the proposed change to the licensing basis will not adversely impact risk, and that NRC approval of the proposal is justified.

D045
1/1

The B&WOG requests approval of this report in order to affirm regulatory acceptance of the 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, or to which the replacement OTSGs are to be designed and fabricated. The intent is to not include large-bore RCS pipe breaks in the design specifications for all OTSG Section XI and safety-related repairs, replacements, modifications, and inspections. 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 plant structures, systems, and components (SSCs), procedures or activities as a result of the NRC's approval of the B&WOG approach. The individual licensees in accordance with applicable NRC regulations will make necessary document revisions.

The B&WOG is requesting an expedited review and approval of this topical report with final approval to be obtained by October 6, 2000. Approval of this report is necessary to support the use of OTSG tube repair hardware and maintenance practices. We are prepared to work with the staff over the next several weeks to appropriately resolve any questions raised by the staff during review of the report.

Please call me at 804/832-3635 if you need any other material for your review of BAW 2374.

Sincerely,

David J Firth
Project Manager
B&W Owners Group Project Management

DJF/bcm

Enclosures

c: SN Bailey - NRR (12 copies)

BAW-2374
Topical Report
July 2000

THE B&W OWNERS GROUP

STEAM GENERATOR COMMITTEE

Justification for Not Including Postulated Breaks in Large-Bore Reactor Coolant System Piping in the Licensing Basis for Existing and Replacement Once-Through Steam Generators

FRAMATOME TECHNOLOGIES

BAW-2374
Topical Report
July 2000

Justification for Not Including Postulated Breaks in Large-Bore Reactor Coolant System Piping in the Licensing Basis for Existing and Replacement Once-Through Steam Generators

Prepared for the
B&W Owners Group
Steam Generator Committee

by
Framatome Technologies, Inc.
Lynchburg, Virginia

Executive Summary

This Topical Report presents the technical basis to support a change to the licensing basis of Babcock & Wilcox-designed nuclear power plants such that they need not include the effects of a break in large-bore reactor coolant system (RCS) piping for once-through steam generator (OTSG) design and maintenance activities. The requested OTSG licensing basis change is to not include the thermal and pressure loads from postulated large-bore RCS pipe breaks. Not including these thermal-hydraulic loads, along with the NRC-approved exclusion of the dynamic loads (Topical Report BAW-1847, "Leak-Before-Break Evaluation of Margins Against Full Break for RCS Primary Piping of B&W Designed NSS"), effectively removes large-bore RCS pipe break from the licensing basis of all pressure boundary and non-pressure boundary parts associated with the OTSG.

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, and therefore a large break loss of coolant (LBLOCA) was 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 LBLOCA 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 LBLOCA as a design condition for OTSG tubes. Therefore, it became prudent to

develop an additional technical basis to not include large-bore RCS pipe break in the licensing basis for the OTSG. This Topical Report provides that technical justification.

Approval of this report will affirm regulatory acceptance of the basis for existing OTSG tube repair hardware and maintenance practices. No additional relaxation will occur as a result of the proposed licensing basis change. 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.

This change to the OTSG licensing basis reduces the potential for premature plugging of steam generator tubes. If the loads resulting from these upper hot leg large-bore pipe breaks were to be included, the limiting loads and resulting tubesheet bore dilations would result in additional restrictions (exclusion zones) for tube repair products, particularly re-roll. This would require additional tube plugging rather than re-rolling the tube. These consequences would be excessively burdensome and unnecessary, considering that the likelihood of the postulated large-bore pipe break is very small, and the consequences of not including it in the licensing basis of the steam generator (possible LOCA-induced steam generator tube rupture) are not risk-significant.

This Topical Report was prepared following the guidance of Regulatory Guide (RG) 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 requirements 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. Low pressure injection (LPI) 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 tube-to-shell temperature difference, which is assumed to induce a steam generator tube rupture (SGTR). Significant primary-to-secondary OTSG leakage is assumed for these sequences, so that the risk estimate will bound any uncertainty associated with OTSG tube integrity. (Operability assessments show that this is a conservative assumption.) The risk analysis includes secondary side isolation failure, which is required in order 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. In addition, only operator actions that are proceduralized have been credited for recovery from these events, using conservative values for human error probability. Even with the assumption that significant OTSG tube failure is a certainty, the ΔCDF is less than 8×10^{-10}/year, and the ΔLERF is less than 4×10^{-11}/year. Relative to the guidelines in RG 1.174, this is considered a "very small" risk increase.

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 proposed licensing basis change maintains sufficient safety margins. In the current OTSG licensing basis, the limiting accident conditions are RCS attached pipe breaks and MSLB. With approval of the B&WOG request to not include large-bore RCS pipe break in the steam generator licensing basis, the limiting accident conditions will remain the same, i.e., 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.

Each B&WOG 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 basis to justify changing the licensing basis of B&W-designed nuclear power plants such that the effects of a break in large-bore RCS piping need not be included for design and maintenance activities of both existing and replacement OTSGs. The basis provided for the proposed licensing basis change has been prepared in accordance with the guidance of Regulatory Guide 1.174. The B&WOG believes that it has demonstrated that the proposed change to the licensing basis will not adversely impact risk, and that NRC approval is justified.

Table of Contents

1.0 Introduction 1-1

1.1 Objective 1-1

1.2 Background 1-1

2.0 Definition of Proposed Change (Element 1) 2-1

2.1 Proposed Change to the Licensing Basis 2-1

2.2 Aspects of the Licensing Basis Affected by the Proposed Change 2-2

2.3 Why the Proposed Change is Needed 2-3

3.0 Engineering Analysis (Element 2): Development of RG 1.174 Principles 3-1

3.1 Meets Current Regulations 3-1

3.2 Change is Consistent with Defense-in-Depth 3-1

3.3 Change Preserves Sufficient Safety Margins 3-3

3.4 Change in CDF and LERF is Small 3-5

3.4.1 Definition of LERF 3-6

3.4.2 Development of LOCA-induced SGTR Scenarios 3-7

3.4.3 Initiating Event Frequency 3-13

3.4.4 Assumption of OTSG Tube RCS Pressure Boundary Damage 3-16

3.4.5 Secondary Side Isolation Failure 3-17

3.4.6 Operator Recovery Action Before Sump Depletion 3-20

3.4.7 Probability Of Independent LPR Failure 3-21

3.4.8 Conditional Probability Of Large Release 3-21

3.4.9 Calculation of ΔCDF and ΔLERF 3-23

4.0 Implementation and Monitoring (Element 3) 4-1

5.0 Summary and Conclusions 5-1

6.0 Certification 6-1

7.0 References 7-1

Appendix A - LOCA Thermal-Hydraulic Evaluation of Maximum Tube-to-Shell Temperature Differences A-1

Appendix B - Evaluation of Manway / Inspection Opening Failures B-1

Appendix C - Evaluation of RCS Hot Leg Piping C-1

Appendix D - Steam Generator Structural and Leakage Integrity for Postulated Large-Bore RCS Pipe Break D-1

Appendix E - 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 E-1

Appendix F - Glossary of Acronyms F-1

List of Tables

Table 3-1 Disposition of Reg. Guide 1.174 Defense-in-Depth Considerations 3-4
Table 3-2 ΔCDF (Sequence 4) 3-24
Table 3-3 ΔLERF (Sequence 7) 3-24
Table 3-4 Summary of Conservatisms in PRA Calculations 3-25

List of Figures

Figure 1-1 OTSG Longitudinal Section 1-5
Figure 1-2 Replacement OTSG Longitudinal Section 1-6
Figure 3-1 Large-Bore Pipe Break Event Tree Considering Steam Generator Tube Failure 3-8

1.0 Introduction

1.1 Objective

This Topical Report presents the technical basis to support a change to the licensing basis of Babcock & Wilcox-designed nuclear power plants such that they need not include the effects of a break in large-bore reactor coolant system (RCS) piping for once-through steam generator (OTSG) design and maintenance activities. The basis provided has been prepared in accordance with the guidance of Regulatory Guide 1.174 (RG 1.174) [1]. 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 hot leg inlet 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 main steam line break, 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 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 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 a 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 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 LBLOCA was 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 LBLOCA conditions. Until 1999, the MSLB transient was used as the limiting accident condition loading for all tube repair hardware. In 1999, the loss of coolant accident (LOCA) of RCS attached pipe was defined as a potential limiting accident condition loading. 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 SBLOCA of an attached pipe.

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 LBLOCA as a design condition for OTSG tubes. Therefore, it became prudent to develop an additional technical basis to not include large-bore RCS pipe break in the licensing basis for the OTSG. This Topical Report provides that technical justification.

As shown in Figure 1-2, the replacement OTSG design is very similar to the existing OTSG design, with tubes rigidly attached to tubesheets at both ends and the associated thermally-induced tube loads. Accordingly , the technical basis developed in this Topical Report for not including large-bore RCS pipe break in the OTSG licensing basis is applicable to the replacement OTSG.

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

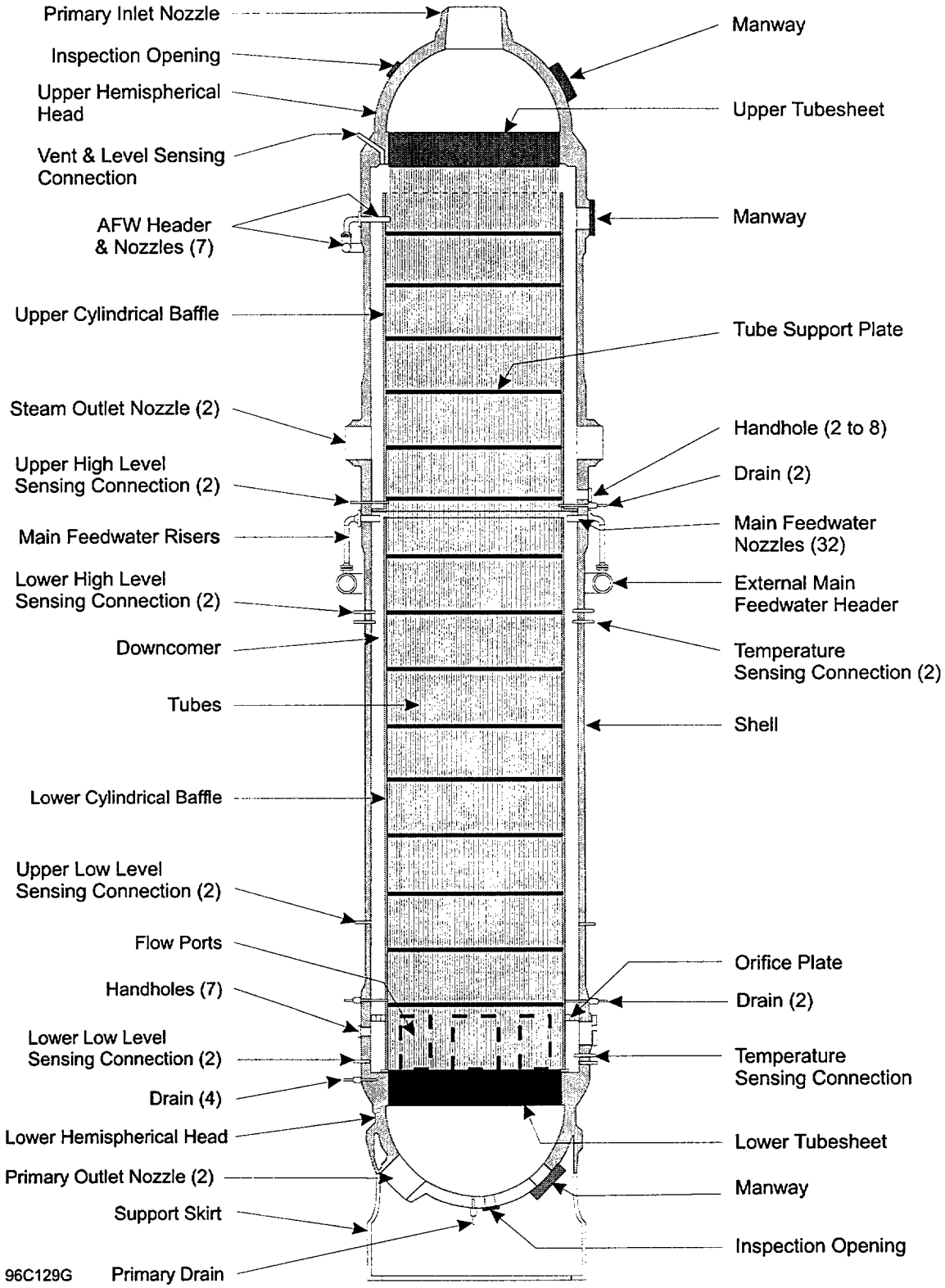
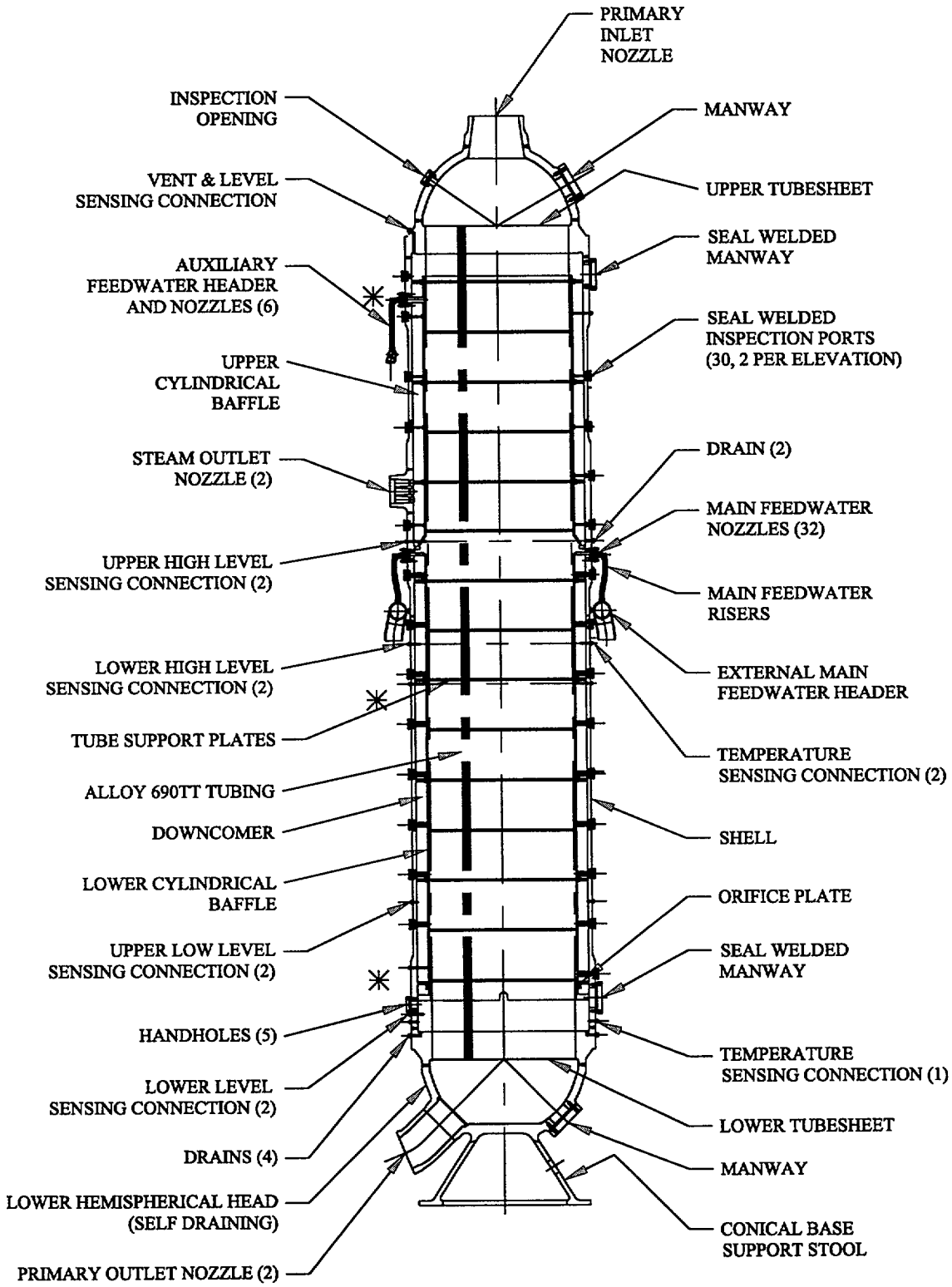


Figure 1-2 Replacement OTSG Longitudinal Section



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. Element 1 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

The proposed change to the licensing basis is that the faulted LOCA OTSG licensing basis need not include the thermal and pressure loads from large-bore RCS pipe breaks in design and maintenance activities for existing and replacement OTSGs. The faulted OTSG condition for primary system LOCA will include the dynamic and thermal-hydraulic loads from breaks in pipes that are attached to RCS large-bore pipes or components.

As indicated in Appendix D (Section D.1), the ASME Code currently allows exclusion of secondary stresses (i.e., thermal stresses) from the OTSG for faulted conditions. The ASME Code allows exclusion of all but the primary OTSG loads. 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 safety analysis for MSLB and SBLOCA. 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 is to not include the effects of large-bore RCS pipe break thermal and pressure loads in the licensing basis of OTSG tubes, repair products, and joints.

Approval of the B&WOG approach of not including the thermal-hydraulic consequences of large-bore RCS pipe break in the OTSG licensing basis, along with the NRC-approved exclusion of the dynamic loads (Topical Report BAW-1847), would effectively keep large-bore RCS pipe break out of the licensing basis of all pressure boundary and non-pressure boundary parts associated with the OTSG. Specific OTSG items include:

- Tubes
- Tube Repair Hardware and Processes (repair rolls, plugs, and sleeves)
- Internals (cylindrical baffles, tube support plates, etc.)
- Shell and Heads
- Steam Generator Supports

This Topical Report applies to both existing and replacement OTSGs.

2.2 Aspects of the Licensing Basis Affected by the Proposed Change

Approval of this report will affirm regulatory acceptance of the 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 include large-bore RCS pipe breaks in the design specifications for all OTSG Section XI and safety-related repairs, replacements, modifications, and inspections. 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 E.) The review concluded that no exemption is required. Approval of this Topical Report (i.e., not including large-bore RCS pipe breaks in the licensing basis of the OTSGs) would not affect any plant's compliance with any regulatory requirement.

There are no other aspects of the plants' licensing basis, including regulations (10 CFR 50), (FSAR) analysis, Technical Specifications, licensing conditions, or licensing commitments that are affected by the proposed change.

2.3 Why the Proposed Change is Needed

Framatome Technologies, Inc. (FTI) 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). A postulated guillotine break near the top of the large-bore hot leg increases the maximum plant-specific shell-to-tube thermal difference to 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.

Not including the effects of large-bore RCS pipe break in the OTSG licensing basis reduces the potential for premature plugging of steam generator tubes. If the loads resulting from these upper hot leg large-bore pipe breaks were to be included, the limiting loads and resulting tubesheet bore dilations would result in additional restrictions (exclusion zones) for tube repair products, particularly re-roll. This would require additional tube plugging rather than re-rolling the tube.

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 not including it in the licensing basis of 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. 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 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. 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 and Appendix E, 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. The change does not result in a significant increase in the challenges to or the failure probability of the barriers. The B&WOG evaluated the potential for OTSG tube failure and determined that the likelihood of barrier failure is small. In addition, should a failure occur, the magnitude of any leakage would be minimal. Appendix D provides a summary of this assessment.

The plant's defenses against common cause failure and human errors are preserved. Relative to human errors, verified and validated emergency operating procedures (EOPs) provide specific guidance on mitigation of transients where OTSG tubes fail (see Section

3.4.5 of this report for additional details). 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 proposed licensing basis change maintains the current safety margins, which are sufficient.

RG 1.174 requires that the engineering evaluation assess whether the impact of the proposed licensing basis change is consistent with the principle that sufficient safety margins are maintained. It goes on to state that, with sufficient safety margins:

- Codes and standards or their alternatives approved for use by the NRC are met.
- Safety analysis acceptance criteria in the licensing basis (e.g., FSAR, supporting analyses) are met, or proposed revisions provide sufficient margin to account for analysis and data uncertainty.

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.

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 in this evaluation.
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 in this evaluation. Existing common cause failures are not impacted.
Independence of barriers is not degraded.	The B&WOG evaluated the potential for SG tube failures and determined that the likelihood of a barrier failure is very small. In addition, should a failure occur, the magnitude of any leakage would be minimal (see Appendix D).
Defenses against human errors are preserved.	No human errors are affected in this evaluation.
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 E).

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 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.

In the current OTSG licensing basis, the limiting accident conditions are RCS attached pipe breaks and MSLB. With approval of the B&WOG request to not include large-bore RCS pipe break in the steam generator licensing basis, the limiting accident conditions will remain the same, i.e., 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, as applicable. Therefore, the design of the OTSG (original and replacement) will continue to meet the safety margins required by the applicable codes and standards after the requested change is approved.

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 catastrophic 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 they are not risk significant (compared to RG 1.174 criteria) and need not be included in the licensing basis.

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 emergency action levels (EALs), based on LOCA symptoms, that will initiate nearly immediate notification of personnel/authorities responsible for site and general emergency planning, including any necessary evacuation of local populations assuring that public health effects are minimized.

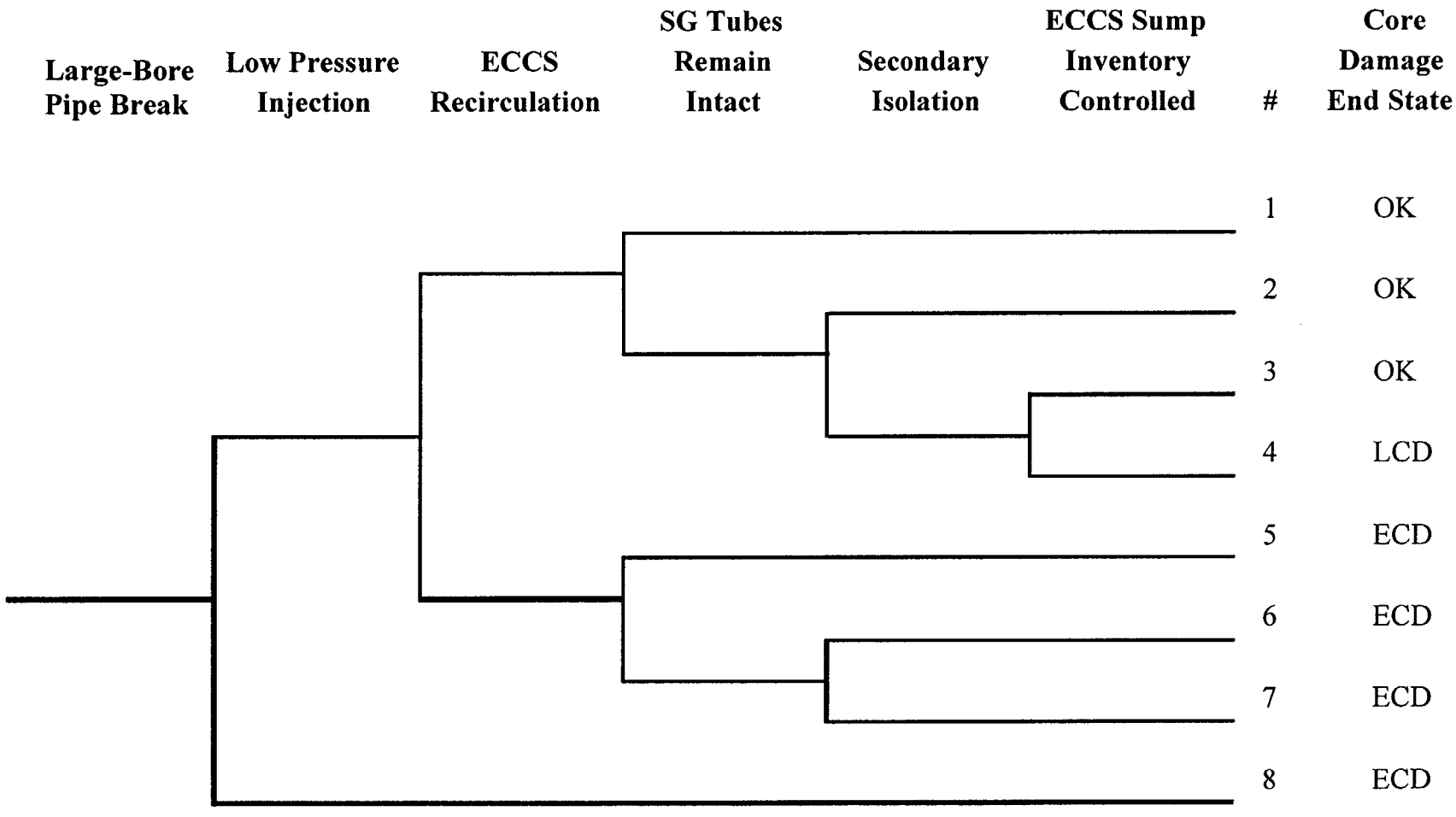
3.4.2 Development of LOCA-Induced SGTR Scenarios

The change in CDF and LERF associated with postulated LOCA-induced SGTR scenarios is estimated below. 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 SBLOCA. 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., "candy cane") region of the RCS hot leg. ECCS low pressure injection (LPI) 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 LPI, which induces a SGTR in the broken RCS loop. Both postulated scenarios involve secondary side isolation failure, but with different results. In

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 assures 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, continued makeup to the RB sump assures 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.

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 LPI recirculation results in early core damage at about 35 minutes after event initiation (the success of LPI 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 (see Appendix D) that the thermally-induced tube loads from these events are not expected to result in significant OTSG leakage. However, significant damage to the OTSG tube pressure boundary is assumed in the PRA sequences, so that the risk estimate will bound any uncertainty associated with SG tube integrity. In addition, only operator actions that are proceduralized have been credited for recovery from these events, using conservative values for human error probability.

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 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 cause consequential OTSG tube failures, analysis indicates that such failures will occur between 12 and 15 minutes following event initiation (see Appendix A). Based on nominal ECCS flow rates, at least 50% of the available ECCS inventory will still remain in the borated water storage tank (BWST) (for subsequent RCS injection) when the tube failure 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 LPI 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. Hence, core damage, if it eventually occurs, will occur late.

EOPs provide EALs based on LOCA symptoms. These symptoms will occur very early in the transient and will initiate 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 LPI 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 (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,
- 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 because, when the SG tubes experience the high tube-to-shell differential temperature following the upper hot leg break, the secondary side pressure is already lower than the primary pressure. This is caused by ECCS liquid condensing steam on the secondary side causing secondary pressure drop below atmospheric pressure when the secondary side is completely isolated. The highest calculated tube-to-shell temperature difference when the secondary side pressure is above the primary is roughly 250°F for the double-ended upper hot leg break. This will not result in significant tube failures or allow enough leakage to dilute the RCS. However, if significant tube leakage were postulated at lower OTSG elevations, i.e., where significant mass transfer could occur, any RCS in-leakage would

flow up the tubes with the ECCS liquid and out of the break. The mixing in the sump would slightly reduce the overall sump concentration but it would be minimal and not of concern. This is true even if the entire OTSG secondary side inventory were instantaneously dumped into the RB sump. Continued secondary to primary leakage will stop when the pressures equilibrate and then reverse, changing the leakage flow direction and minimizing the potential for continued dilution of the sump. Even if RCS pressure remains lower than secondary side pressure for an extended period of time (highly improbable), EOP guidance addresses eventual termination of feedwater to the OTSG. This will effectively stop boron dilution when the secondary side level decreases to below the elevation of the tube break. For these reasons, the boron dilution scenario 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 pressurizer surge line (see Appendix A). This is the only location where a break may possibly produce OTSG tube thermal loads significantly in excess of those analyzed.

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 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 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. Appendix C contains an evaluation of the RCS hot leg piping in the B&WOG plants, which also 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 the 3362 years of operation (this is conservative since no TW cracks have been experienced in pipes larger than 8 inches), 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:

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

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, a consequential SGTR in the affected loop is not expected to occur. The thermally-induced tube loads are not expected to result in significant tube leakage. A scoping analysis (see Appendix D) indicates that the resulting tube leakage is relatively benign. In addition, at the time of the high temperature difference, and for the duration of the event, there is a very small pressure difference across the tubes. 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.

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. As indicated in Appendix D, the expected tube leakage from a break in the upper hot leg is not catastrophic. Significant primary-to-secondary leakage is assumed for these scenarios, so that the risk estimate will bound any uncertainty associated with SG tube integrity.

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.

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 (~ 50 psig and decreasing due to RB spray operation), 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 automatic 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.

The B&WOG members' EOPs use a symptom approach to identify and mitigate abnormal transients. This eliminates the need to determine what has failed (i.e., identify the initiating event(s)) in order to mitigate abnormal transients successfully. Also, these EOPs provide a hierarchy for treatment of symptoms where loss of RC subcooling margin (SCM) has the highest priority and is, therefore, treated first. Following this, indications of inadequate and excessive primary-to-secondary heat transfer are treated as the next level of priority. After assessing plant parameters for these symptoms, indications of SGTR are addressed. SGTR is the only transient that is addressed as an event. This is because it has unique indications allowing it to be easily identified and because by treating a SGTR as an event, the operator can significantly reduce radiation release.

For the postulated event of a large-bore pipe break, such as a double-ended break of a hot leg, RC SCM will be lost within seconds following event initiation. EOPs will direct operators to trip reactor coolant (RC) pumps, initiate full HPI and LPI, verify core flood tanks (CFTs) discharge, ensure RB spray is operating and raise OTSG levels to the loss of SCM level setpoint. EOPs then provide guidance to determine if primary-to-secondary heat transfer is needed (i.e., to augment core energy removal through the break) and, if so, to ensure SGs are available. In the postulated situation, ECCS (HPI and LPI) flow rates will be at full flow, CFTs will have fully discharged with RCS and RB pressures initially equilibrating at ~ 50 psig and RB spray 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 uncontrollably transferred to the RB. (Also, additional energy removal by the SGs, if possible, is very limited due to the RCS leak size.) The faulted OTSG will eventually depressurize below

RCS pressure, a necessary condition for large early releases, indicating existence of a secondary side leak. EOPs deal with such indications by providing guidance to isolate the leak.

Following treatment of the loss of SCM, and checks for the need of OTSG core energy removal, EOPs provide guidance to check for indication of a SGTR. Given the postulated tube failure, i.e., "significant" primary-to-secondary leakage in one OTSG, indications of the tube leak from main steam line radiation monitors, off-gas monitors and rising OTSG level will be clear and easily discerned by operators. EOPs provide guidance to isolate non-essential steam loads from the faulted OTSG, commence make-up to the BWST, and to isolate the faulted OTSG if overfill cannot be prevented or integrated radiation release dose limits could exceed plant limits. Because the faulted OTSG level will be at the elevated loss of SCM level setpoint, and given the postulated significant tube leakage, high OTSG levels will most probably be attained early in the transient leading to OTSG isolation. Guidance to isolate the OTSG includes atmospheric and turbine dump valves, which represent the most probable isolation failure sites that can accommodate the postulated significant tube leakage. This EOP guidance will also isolate turbine-driven feed pump steam supply lines and feedwater lines.

Relative to secondary side leaks, the likelihood of a stuck open main steam safety valve (MSSV) is much less than for other accidents. For the largest break sizes, the MSSVs will not be challenged. Some safety valves may open for intermediate size breaks, but there would not be cycling such as might occur for small breaks and lesser transients. The secondary side pressure will drop rapidly to below 50 psig, even if no safety valves are open, because the secondary side pressure will follow the decrease of the primary side pressure. 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. In addition, if the safety valves are challenged at all, it will be well before the OTSG

tubes are postulated to fail. 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.

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 judgement, and considers human performance as supported by plant integrated emergency drills.

3.4.6 Operator Recovery Action Before Sump Depletion

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

The potential loss of inventory will occur following a period of extended 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 be dependent 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 more than adequate time for operator action to isolate the faulted SG and/or replenish primary inventory.

Operator recovery opportunities include isolation of the secondary side leakage and replenishment of the primary inventory. Also, once SCM is restored, operators will minimize SCM by throttling ECCS injection flow rates; the lower the SCM maintained, the lower the secondary side leak rate and the longer will be the recovery time available before onset of core damage. A conservative human error probability (HEP) of 0.1 is assumed for these operator actions.

A review of the utility procedures indicates that the conservative HEP assumption is well supported. All of the referenced operator actions, including those to isolate the faulted OTSG and commence early RCS inventory makeup via make up to the BWST, are contained in the EOPs. Isolating the failed OTSG is the simplest action but could fail if the leak is from an MSSV (highly improbable for the scenario of interest). However, if early isolation of the OTSG fails, injecting water into the RB (referenced in shift technical advisor and technical support center guidelines) would help maintain level in the RB emergency sump that could allow recirculation to continue with a primary-to-secondary leak. 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 LPR Failure

For the LERF sequence (sequence 7), there must be an independent failure of LPI recirculation, conditional upon success of LPI. 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 value for this failure probability 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 occurs at about 35 minutes after event initiation because the ECCS fails to establish low pressure recirculation (probably due to failure of switchover to the RB sump recirculation). 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 occurs between 12 and 15 minutes after event initiation (see Appendix A). Therefore, primary system fluid will be leaking out of the ruptured OTSG tubes into the secondary side for at least 20 minutes before core damage occurs. This will provide some water in the secondary side for scrubbing, even if feedwater has been isolated.

The location of the failed isolation valve 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 atmospheric dump valves (ADVs), turbine bypass valves (TBVs), and turbine-driven emergency feedwater pump steam supply valves (however, pump will not be running). Leaks through ADVs and turbine-driven emergency feedwater pump will discharge to the atmosphere, while leaks through the TBVs will discharge to the condenser. However, all of these pathways have redundant valves for isolation, and the guidance in the EOPs provides for their isolation (see Section 3.4.5).

Other 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.

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.

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 including large-bore RCS pipe break in the OTSG licensing 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. Even with the assumption that OTSG tube failure resulting in significant leakage is a certainty, the ΔCDF is less than 8×10^{-10}/year, and the ΔLERF is less than 4×10^{-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 assures 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.

Table 3-2 ΔCDF (Sequence 4)

Failure	
LOCA in hot leg candy cane	8×10^{-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 LPR failure/core damage	0.1
	$<8 \times 10^{-10}$/year

Table 3-3 ΔLERF (Sequence 7)

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

Table 3-4 Summary of Conservatisms in PRA Calculations

ELEMENT OF RISK ANALYSIS	CONSERVATISMS	APPLIES TO
Estimate of Large 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) • Appendix D supports limited leakage • Thermal hydraulic analyses which 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 do not cause MSSVs to open • No liquid challenge to MSSVs • EOPs address necessary actions • Conservative HEP	Sequences 4 & 7
Prevent Depletion of ECCS Sump	• Low driving force (ΔP) for loss of inventory • Long time before loss of ECCS • Variety of makeup options available	Sequence 4 Only
Failure of Low Pressure ECCS Recirculation	• Bounding failure rate from B&WOG PRAs	Sequences 4 & 7
Conditional Probability of Large Release	• Low primary system pressures limit the flow rate of fission products to the secondary side • The secondary side is a circuitous pathway to the environment • Pathway is likely to be wet, providing scrubbing	Sequences 4 & 7

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 new 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. Degradation in 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. For the large-bore RCS pipe break event, the probabilistic analysis presented in Section 3.4 is conservative with respect to assumptions of OTSG tube leakage. The proposal to not include that event in the licensing basis of the OTSG is not expected to affect the integrity of the steam generator tubes (under either normal or accident conditions).

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 Draft NEI 97-06 [9].

5.0 Summary and Conclusions

This Topical Report presents the technical basis to justify changing the licensing basis of B&W-designed nuclear power plants such that the effects of a break in large-bore RCS piping need not be included for design and maintenance activities of both existing and replacement OTSGs. The requested OTSG licensing basis change is to not include the thermal and pressure loads from postulated large-bore RCS pipe breaks. Not including these thermal-hydraulic loads, along with the NRC-approved exclusion of the dynamic loads (Topical Report BAW-1847), effectively removes large-bore RCS pipe break from the licensing basis of all pressure boundary and non-pressure boundary parts associated with the OTSG.

The basis 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 of RG 1.174 have been demonstrated for the proposed change.

- Meets current regulations
- 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 to show that they are not risk-significant (compared to RG 1.174 criteria) and need not be included in the licensing basis. PRA sequences have been developed that model 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 guidelines in RG 1.174. These results demonstrate that the likelihood of

occurrence is sufficiently low and the mitigation capability sufficiently robust that the large-bore pipe breaks need not be considered in the OTSG licensing basis.

The B&WOG believes that it has demonstrated that the proposed change to the licensing basis will not adversely impact risk, and that NRC approval is justified.

6.0 Certification

The below signatures certify that the Topical Report is accurate and complete.

BAW-2374 Main Report: Justification for Change to OTSG Licensing Basis

Prepared by:		Reviewed by:	
RS Enzinna, Sr. Principal Engineer, Risk & Reliability Analysis	7-5-00 Date	SH Levinson, Advisory Engineer, Risk & Reliability Analysis	7/5/00 Date

Appendix A: Evaluation of Tube-to-Shell Temperature Differences

Prepared by:		Reviewed by:	
JA Klingenfus, Sr. Supervisory Engineer, Analysis Services	7/5/00 Date	DR Page, Engineer, LOCA Methods	7/5/00 Date

Appendix B: Evaluation of Manway/Inspection Opening Failures

Prepared by:		Reviewed by:	
SH Levinson, Advisory Engineer, Risk & Reliability Analysis	7/5/00 Date	SB Brown, Manager, Steam Generator Engineering	7/5/00 Date

Appendix C: Evaluation of RCS Hot Leg Piping

Prepared by:		Reviewed by:	
MA Rinckel, Project Engineer, B&WOG Generic License Renewal	7/5/00 Date	SH Levinson, Advisory Engineer, Risk & Reliability Analysis	7/5/00 Date

Appendix D: Steam Generator Integrity for Large-Bore RCS Pipe Break

Prepared by:		Reviewed by:	
DE Costa, Sr. Principal Engineer, Steam Generator Engineering	7/5/00 Date	SB Brown, Manager, Steam Generator Engineering	7/5/00 Date

Appendix E: Evaluation of General Design Criteria

Prepared by:		Reviewed by:	
MW Epling, Project Manager, B&WOG Licensing Working Group	7/5/00 Date	JJ Kelly, Manager of Owners Group Services	7/5/00 Date

Approved by:	
DJ Firth, Project Manager, B&WOG Steam Generator Committee	7/5/00 Date

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] Draft NEI 97-06, Rev 1B-BTS, "Steam Generator Program Guidelines," April 2000.

Appendix A

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

Table of Contents

A.1 Introduction and Background A-5

A.2 RCS Evolution for the Large-Bore RCS Pipe Break Spectrum A-6

A.2.1 Cold Leg Pump Discharge (CLPD) Break A-8

A.2.2 Cold Leg Pump Suction (CLPS) Break A-9

A.2.3 Hot Leg Breaks A-10

A.3 Structural Break Classifications A-13

A.4 Analyzed Tube-to-Shell Temperature Differences A-16

A.4.1 Limiting Upper Hot Leg Break A-17

A.4.2 Pressurizer Surge Line Breaks A-21

A.4.3 Davis-Besse Continuous Head Vent Line Break A-22

A.5 Composite Tube-to-Shell Temperature Difference Estimates A-24

A.6 Thermal-Hydraulic Summary and Conclusions A-30

A.7 References A-30

List of Tables

Table A-1 Lowered-Loop Plant Hot Leg Pipe or SG Upper Plenum Connections. A-15

Table A-2 Raised-Loop Plant Hot Leg Pipe or SG Upper Plenum Connections A-16

Table A-3 Key Boundary Conditions for SG Tube Load Analysis A-20

Table A-4 Maximum Thermal Difference Benchmark Comparisons. A-26

Table A-5 Lowered-Loop Plant Tube-to-Shell Temperature Approximations A-28

Table A-6 Raised-Loop Plant Tube-to-Shell Temperature Approximations..... A-29

List of Figures

Figure A-1 177-FA Lowered-Loop RCS Conditions Following a CLPD Break A-31

Figure A-2 177-FA Lowered-Loop RCS Conditions Following a Pressurizer Surge Line Break A-32

Figure A-3 177-FA Lowered-Loop RCS Conditions Following a Hot Leg U-Bend Break. A-33

Figure A-4 177-FA Raised-Loop RCS Conditions Following a Pressurizer Surge Line Break. A-34

Figure A-5 177-FA Raised-Loop 14.4 Sq ft DE Hot Leg Break Broken Loop Shell and Tube Temperatures..... A-35

Figure A-6 177-FA Raised-Loop 14.4 Sq ft DE Hot Leg Break Intact Loop Shell and Tube Temperatures..... A-35

Figure A-7 177-FA Raised-Loop 14.4 Sq ft DE Hot Leg Break Primary and Secondary Pressures. A-36

Figure A–8 177-FA Raised-Loop 14.4 Sq ft DE Hot Leg Break Tube to Shell Temperature and Pressure Differences..... A-36

Figure A-9 177-FA Raised-Loop 0.42 Sq ft Pzr Surge Line Break Broken Loop Shell and Tube Temperatures A-37

Figure A-10 177-FA Raised-Loop 0.42 Sq ft Pzr Surge Line Break Intact Loop Shell and Tube Temperatures A-37

Figure A-11 177-FA Raised-Loop 0.42 Sq ft Pzr Surge Line Break Primary and Secondary Pressures. A-38

Figure A-12 177-FA Raised-Loop 0.42 Sq ft Pzr Surge Line Break Tube to Shell Temperature and Pressure Differences. A-38

Figure A-13 177-FA Lowered-Loop 0.42 Sq ft Pzr Surge Line Break Broken Loop Shell and Tube Temperatures A-39

Figure A-14 177-FA Lowered-Loop 0.42 Sq ft Pzr Surge Line Break Intact Loop Shell and Tube Temperatures A-39

Figure A-15 177-FA Lowered-Loop 0.42 Sq ft Pzr Surge Line Break Primary and Secondary Pressures. A-40

Figure A–16 177-FA Lowered-Loop 0.42 Sq ft Pzr Surge Line Break Tube to Shell Temperature and Pressure Differences. A-40

Figure A-17 177-FA Raised-Loop 0.049 Sq ft Upper Head Vent Break Broken Loop Shell and Tube Temperatures A-41

Figure A-18 177-FA Raised-Loop 0.049 Sq ft Upper Head Vent Break Intact Loop Shell and Tube Temperatures A-41

Figure A-19 177-FA Raised-Loop 0.049 Sq ft Upper Head Vent Break Primary and Secondary Pressures. A-42

Figure A–20 177-FA Raised-Loop 0.049 Sq ft Upper Head Vent Break Tube to Shell Temperature and Pressure Differences. A-42

Figure A-21 177-FA Lowered-Loop Plant Estimated Maximum Tube-to-Shell Temperature Differences versus Break Size and Location. A-43

Figure A-22 177-FA Raised-Loop Plant Estimated Maximum Tube-to-Shell Temperature Differences versus Break Size and Location. A-44

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 Technologies, Inc. (FTI) and the B&W Owners Group (B&WOG) also implicitly credited LBB considerations in determining the bounding tube-to-shell temperature differences from which thermal loads on the steam generator tubes were calculated. LBB credit to restrict the break locations to the attached pipes for the maximum thermal loads was not explicitly granted by the LBB Safety Evaluation Report (SER). Therefore, because the maximum tube thermal loads from a non-mechanistic break in the upper hot leg large bore pipe have not been analyzed or evaluated, initial plant operability assessments were completed. The assessments concluded that although the thermal loads are significantly in excess of the previously-analyzed pressurizer surge line break, a large break in the upper hot leg region would not result in undue risk to the public because no gross tube failure or leakage was predicted or expected. The

assessments preceded this Regulatory Guide 1.174 risk-informed submittal to specifically exclude large bore RCS pipe breaks from consideration in defining the thermal loads for steam generator design calculations.

As a requisite for a formal operability assessment or a risk-informed submittal, an evaluation of the characteristic tube-to-shell thermal consequence from any break in the large bore RCS piping was completed. This evaluation postulates 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 thoroughly reviewing the RCS thermal-hydraulic behavior following this spectrum of breaks, the worst size and location was determined, and a representative thermal-hydraulic analysis was completed to provide a typical generic tube-to-shell temperature difference. This result was 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 excluded. 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 elimination of all large-bore pipe breaks from the steam generator thermal design-basis. The evaluation of the characteristic LOCA thermal consequences for all break sizes was also used to determine which attached pipe breaks are potentially limiting transients that should be used to define the steam generator (SG) thermal load design basis if the large bore exclusion 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 shell and tube axially-averaged temperature, 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 it 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 comparable 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 tube liquid level (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 contribute to 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 (BWST versus sump recirculation). 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 cursory evaluations, it may be prudent to conservatively ignore the ECCS liquid heat up term in some of the cases. Exclusion of this term also addresses any low decay heat cases, although this approach is not consistent with the nominal or typical initial conditions from which the LOCA is postulated.

For the largest break sizes, the maximum 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 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 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 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

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 circumferential 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. The thermal loads were not explicitly excluded by the LBB methodology SER [A-2], so a Regulatory Guide 1.174 submittal is being made to request exemption from large bore pipe break thermal loads as well. If the NRC grants approval for this approach, then the limiting LOCA thermal loads (as well as the dynamic loads) will be generated as a consequence of an attached pipe break.

Based on the discussions 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. Any attached pipe that connects to the hot leg will 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. The tables also give 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 Appendix B). Based on the material given in this submittal, the B&W Owners Group seeks to not include the thermal loads from a SG manway or inspection port LOCA in addition to LOCAs in the large bore pipes.

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	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 have a 6 inch inspection opening (0.196 ft^2 area) at the same elevation.

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. The Regulatory Guide 1.174 submittal requires that the consequences of the excluded 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 the 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 determines 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 $\Delta T_{tube\text{-}to\text{-}shell}$ (F)	Time of Maximum (sec)	Maximum $\Delta T_{tube\text{-}to\text{-}shell}$ (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. 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. 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 $\Delta T_{t\text{-}t\text{-}s}$ (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)
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 hot leg pipe, because these breaks can generate significantly higher SG tube thermal loads than the analyzed pressurizer surge line break. The maximum thermal difference for an upper CLPD or CLPS large bore pipe break on a lowered-loop plant was estimated to be similar to, but slightly less limiting than that calculated for the pressurizer surge line. The large bore pipe evaluations for the raised-loop plant concluded only the hot leg breaks could produce higher tube loads than the pressurizer surge line break (i.e. the cold leg breaks are much less severe). 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.

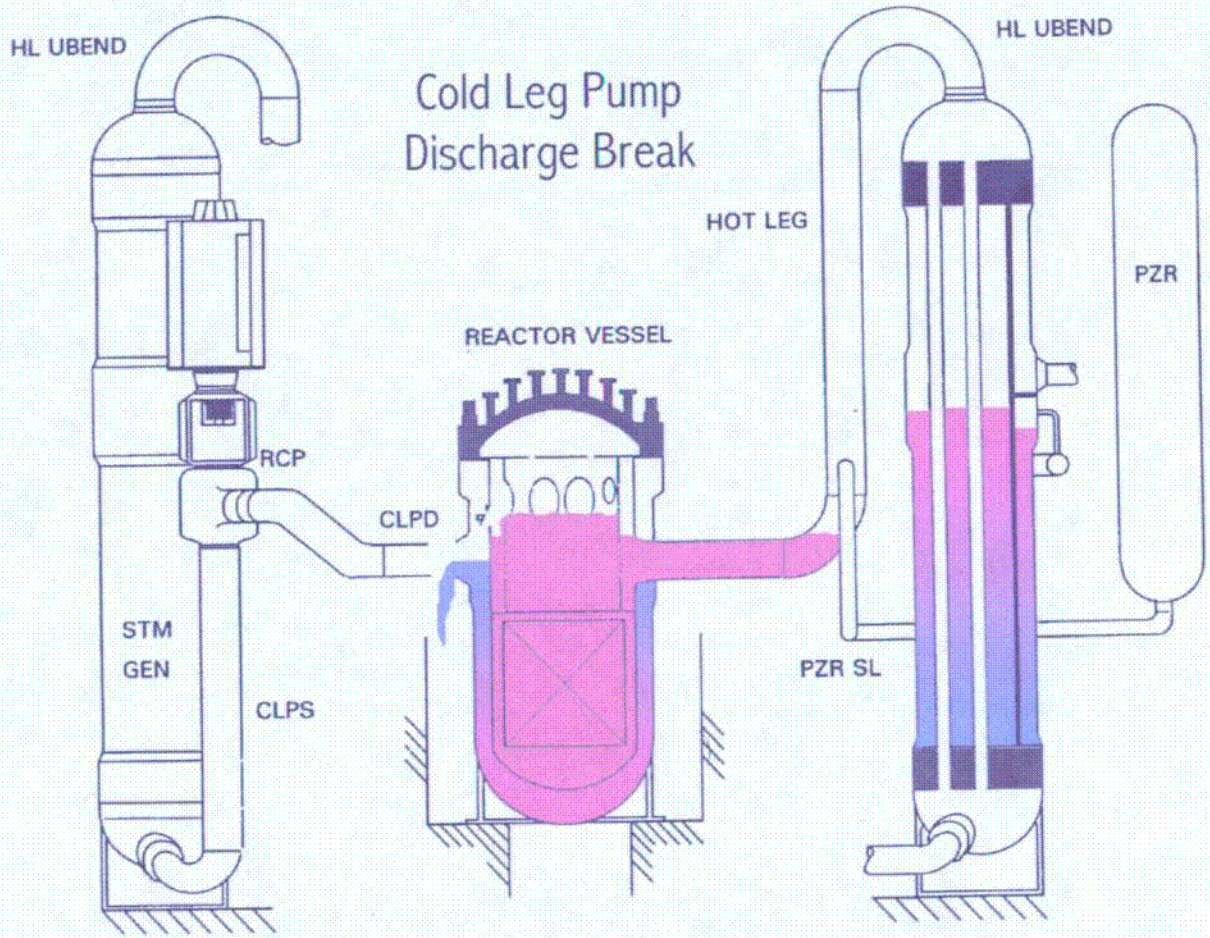
A.7 References

[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.

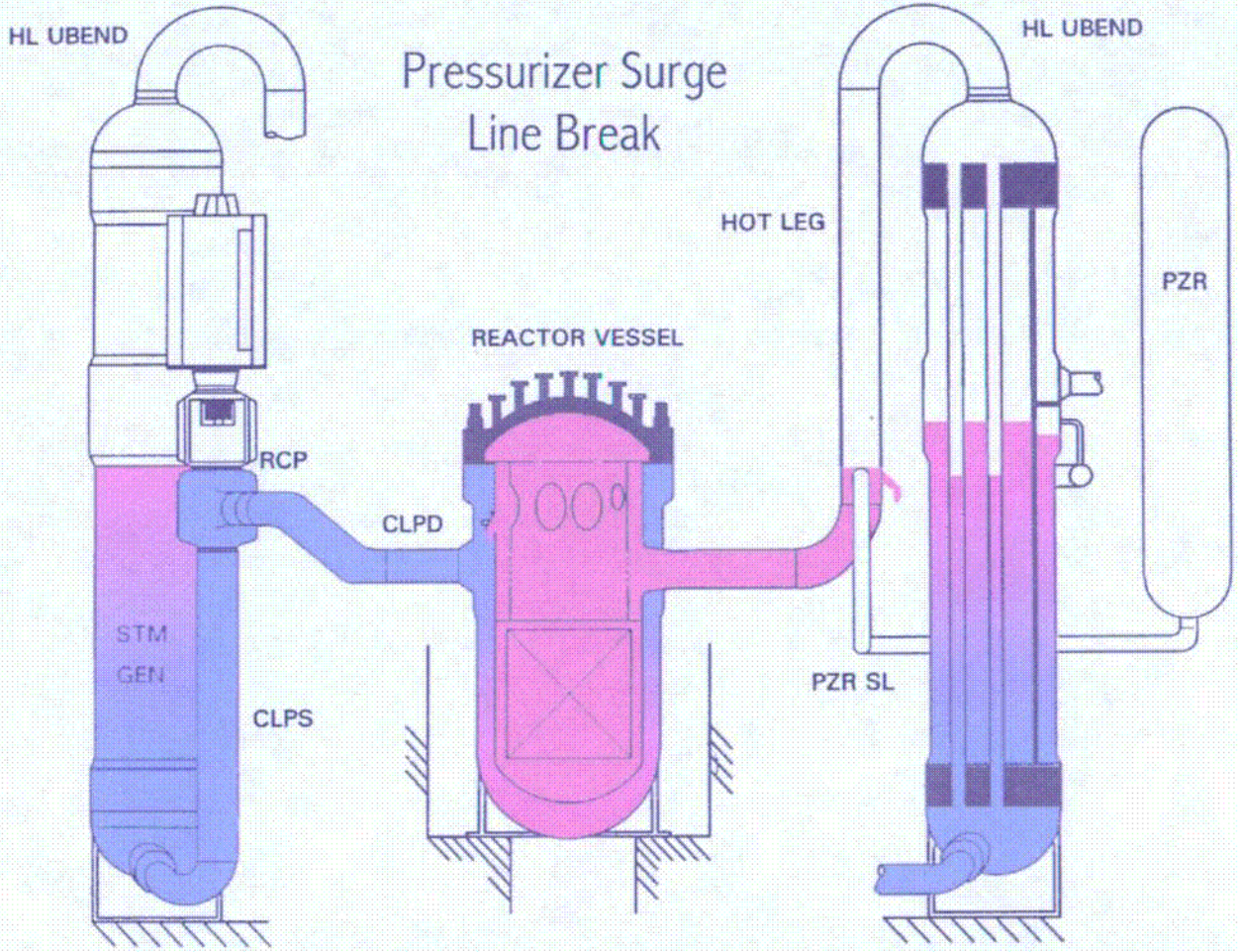
[A-3] FTI Topical Report BAW-2243A, "The B&W Owners Group Generic License Renewal Program, Demonstration of the Management of Aging Effects for the Reactor Coolant System Piping," June 1996.

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



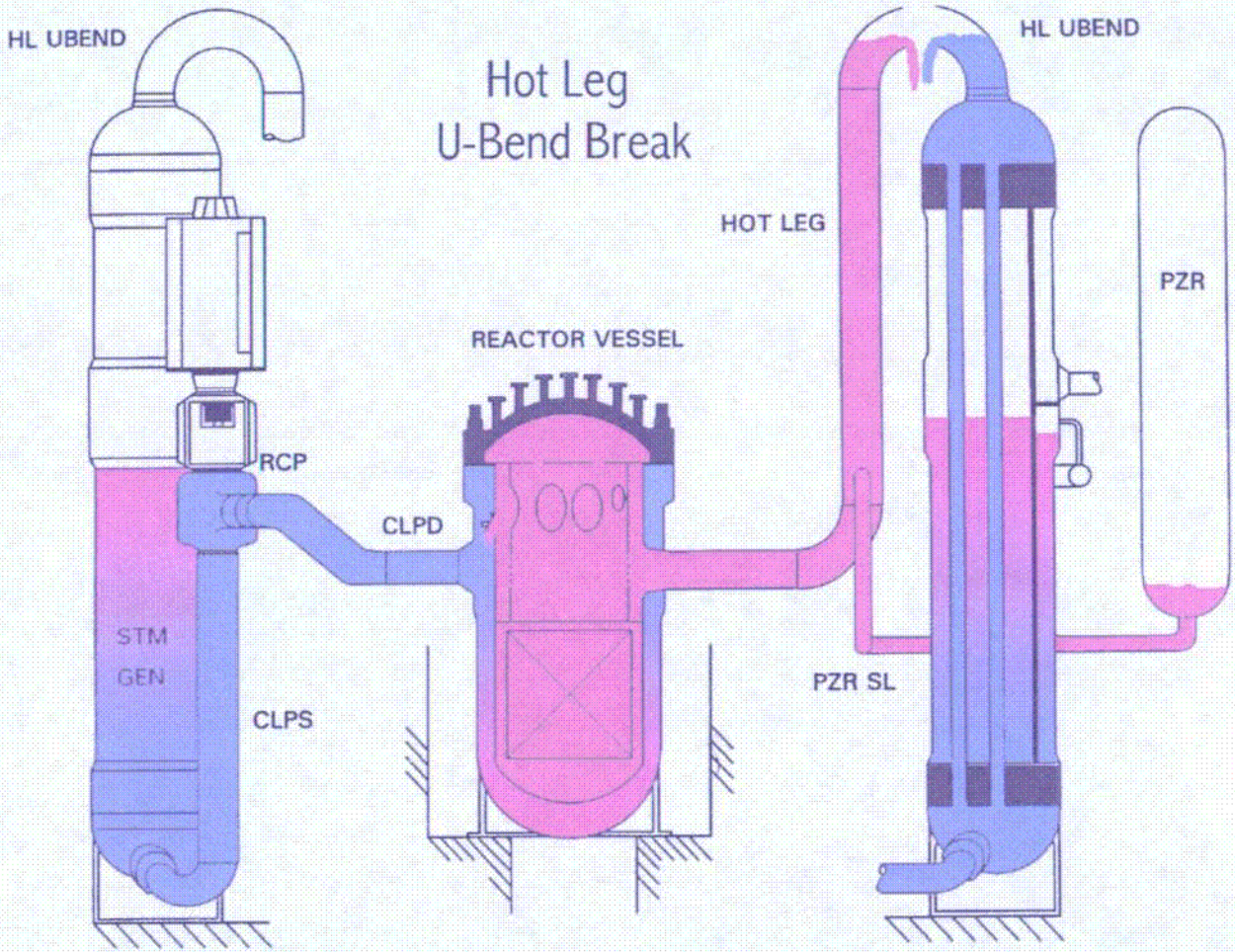
C-1

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



C-2

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



C-3

C-4

Figure A-4 177-FA Raised-Loop RCS Conditions Following a Pressurizer Surge Line Break

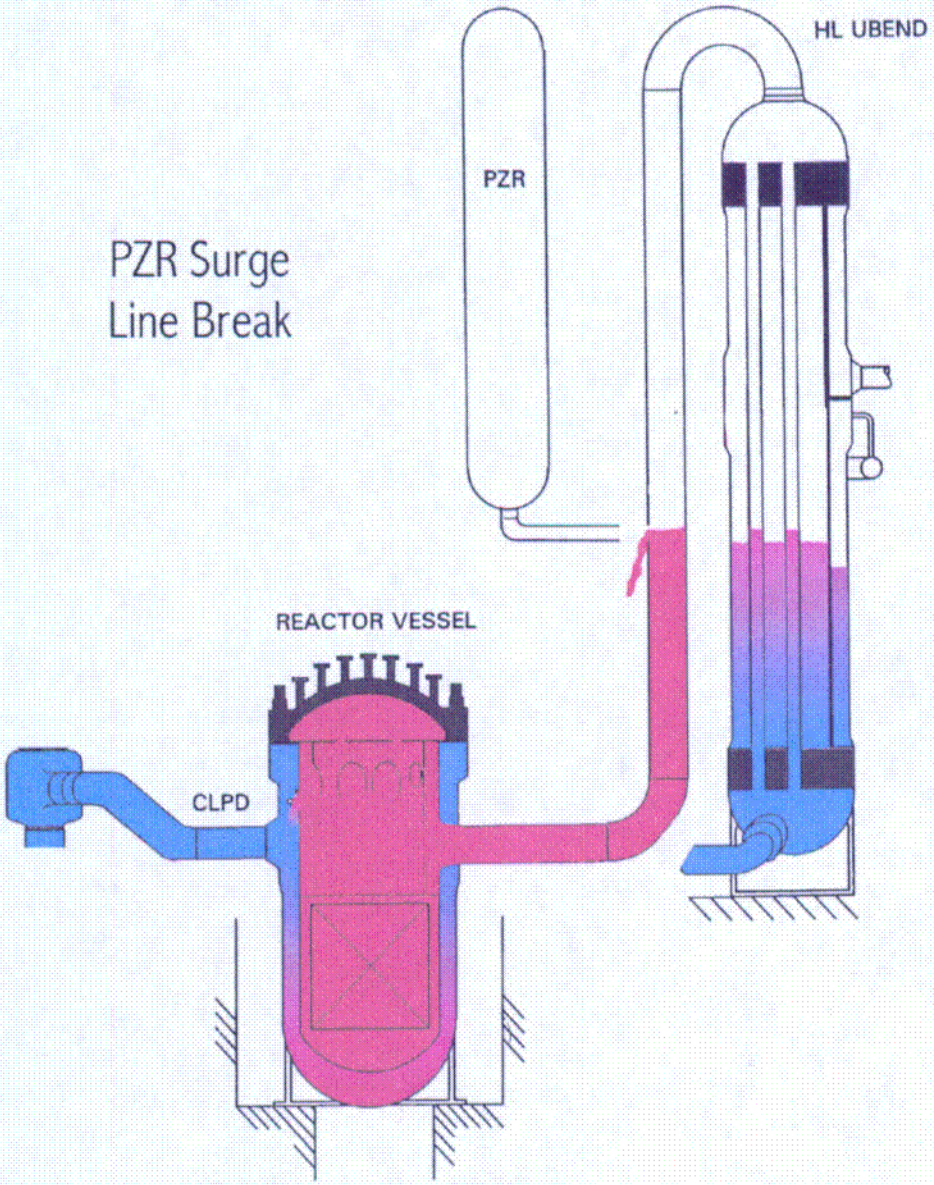


FIGURE A-5. 177-FA Raised-Loop 14.4 Sq ft DE Hot Leg Break
Broken Loop Shell and Tube Temperatures

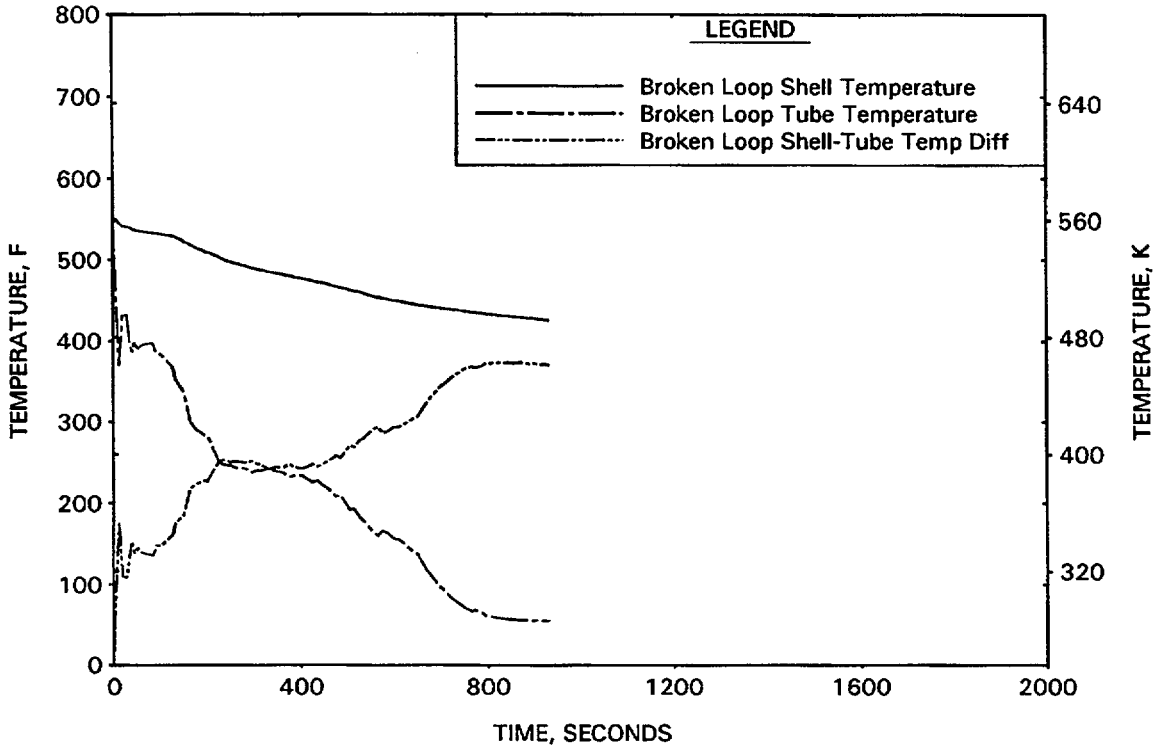


FIGURE A-6. 177-FA Raised-Loop 14.4 Sq ft DE Hot Leg Break
Intact Loop Shell and Tube Temperatures

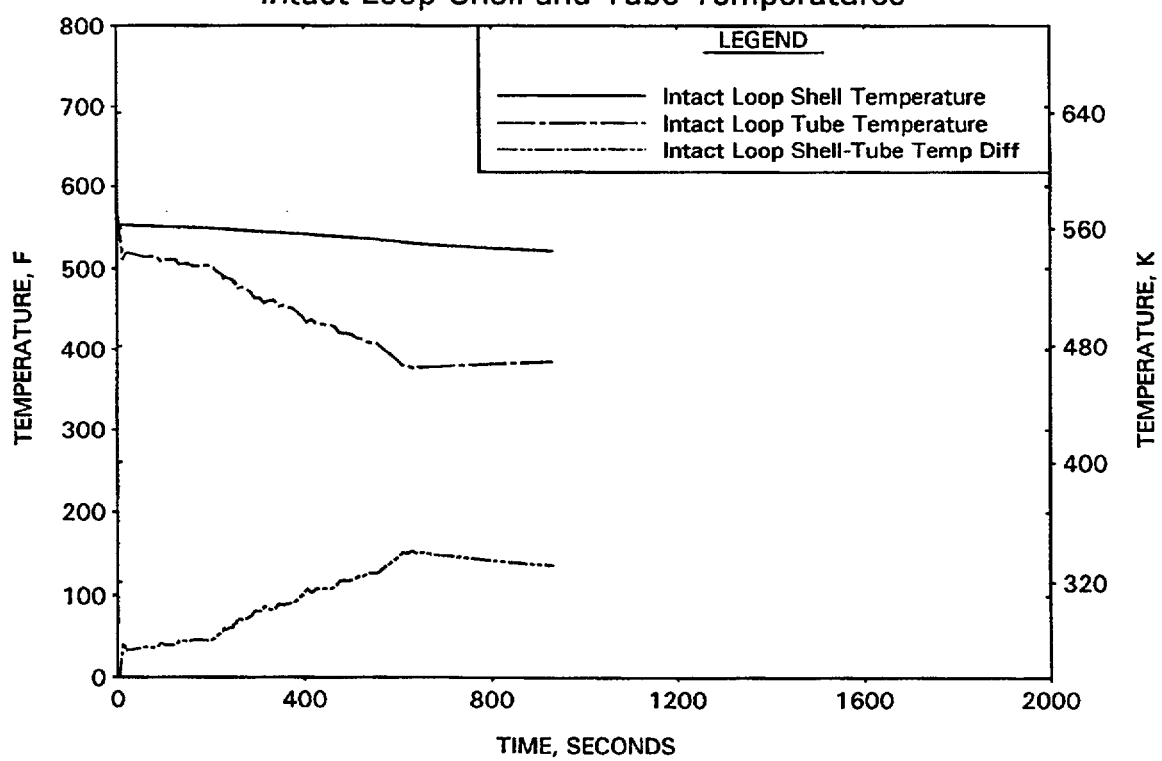


FIGURE A-7. 177-FA Raised-Loop 14.4 Sq ft DE Hot Leg Break
Primary and Secondary Pressures

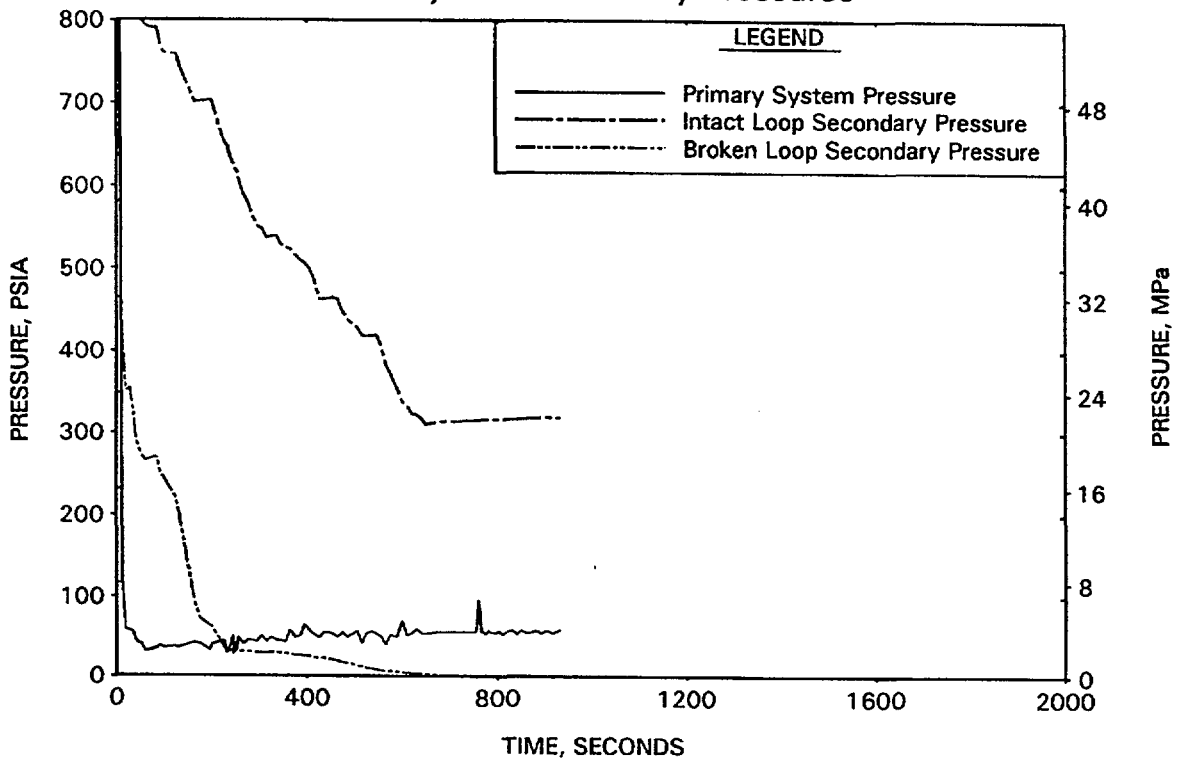


FIGURE A-8. 177-FA Raised-Loop 14.4 Sq ft DE Hot Leg Break
Tube to Shell Temperature & Pressure Differences

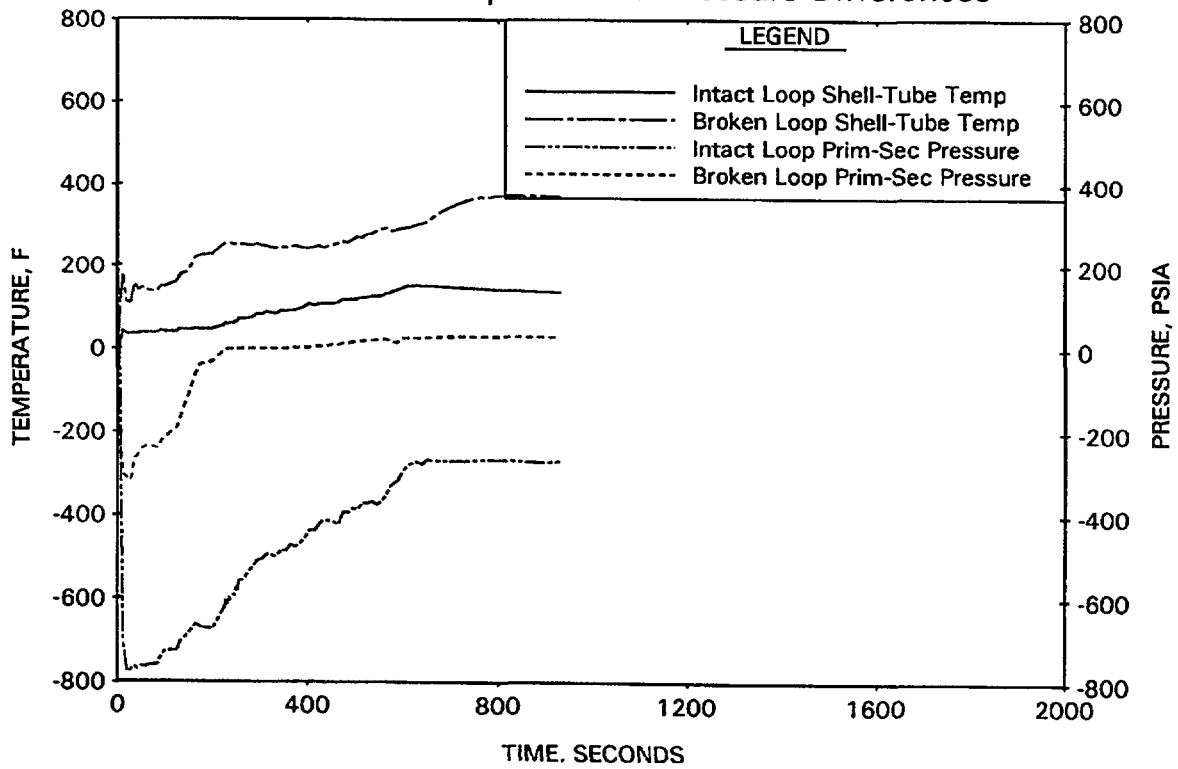


FIGURE A-9. 177-FA Raised-Loop 0.42 Sq ft PZR Surge Line Break
Broken Loop Shell and Tube Temperatures

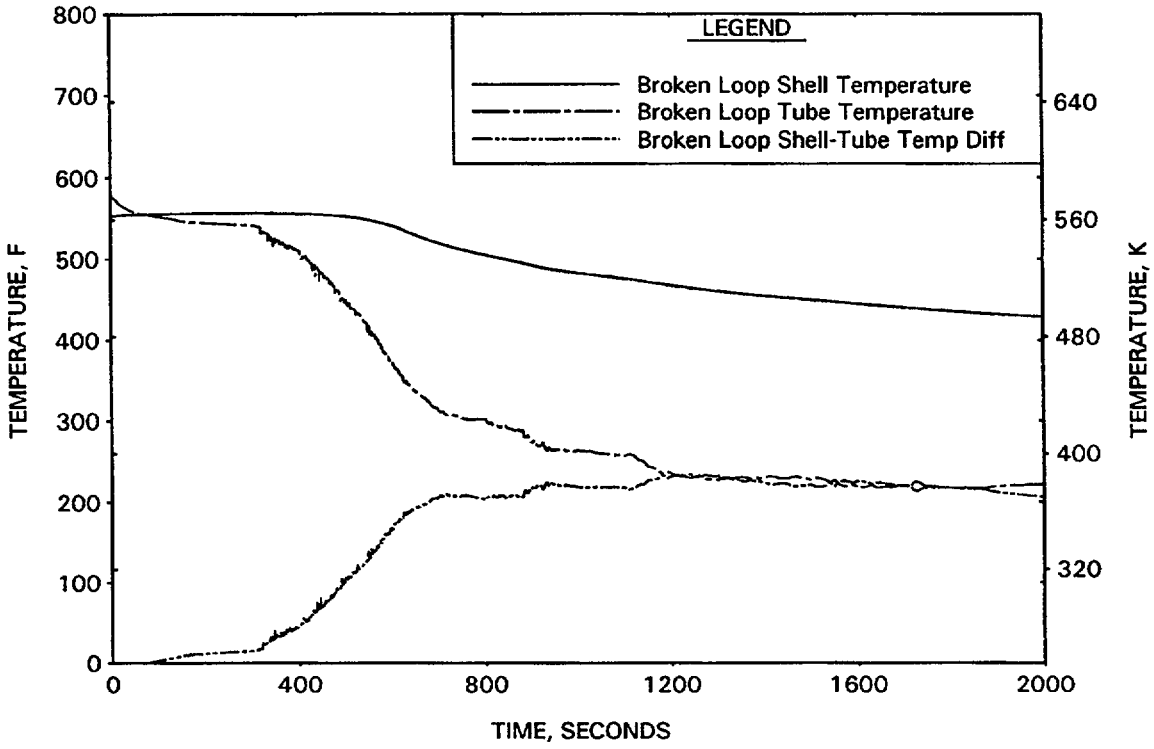


FIGURE A-10. 177-FA Raised-Loop 0.42 Sq ft PZR Surge Line Break
Intact Loop Shell and Tube Temperatures

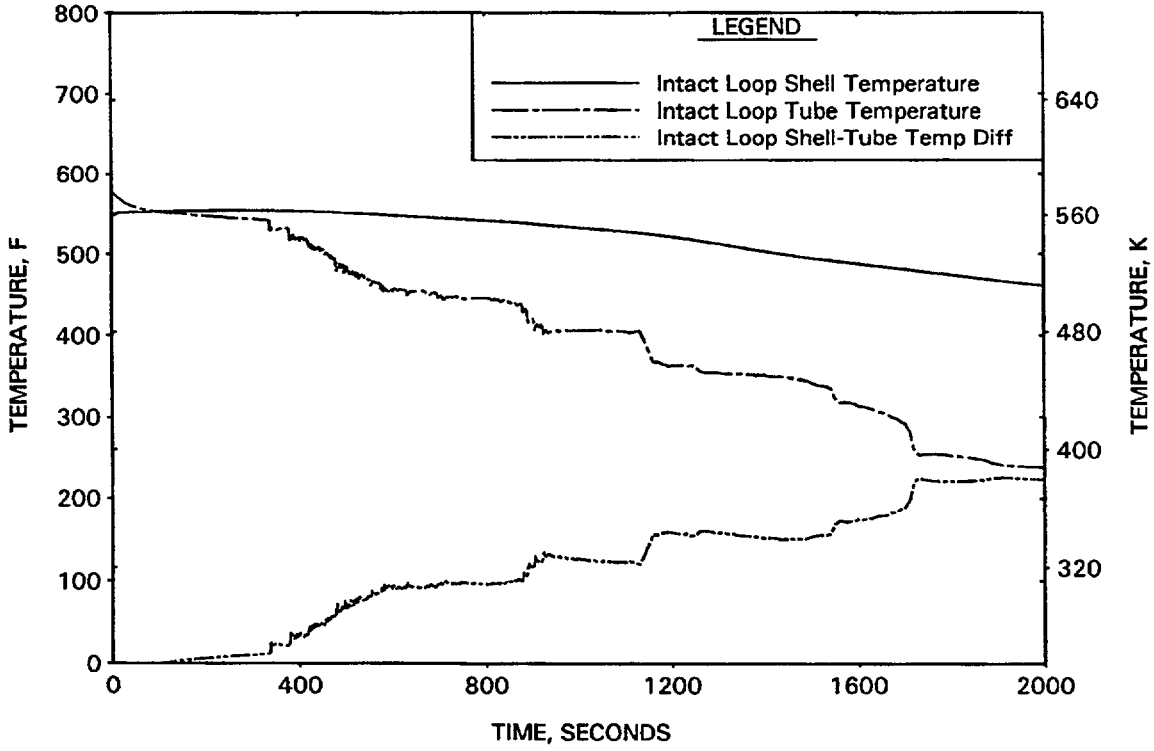


FIGURE A-11. 177-FA Raised-Loop 0.42 Sq ft PZR Surge Line Break
Primary and Secondary Pressures

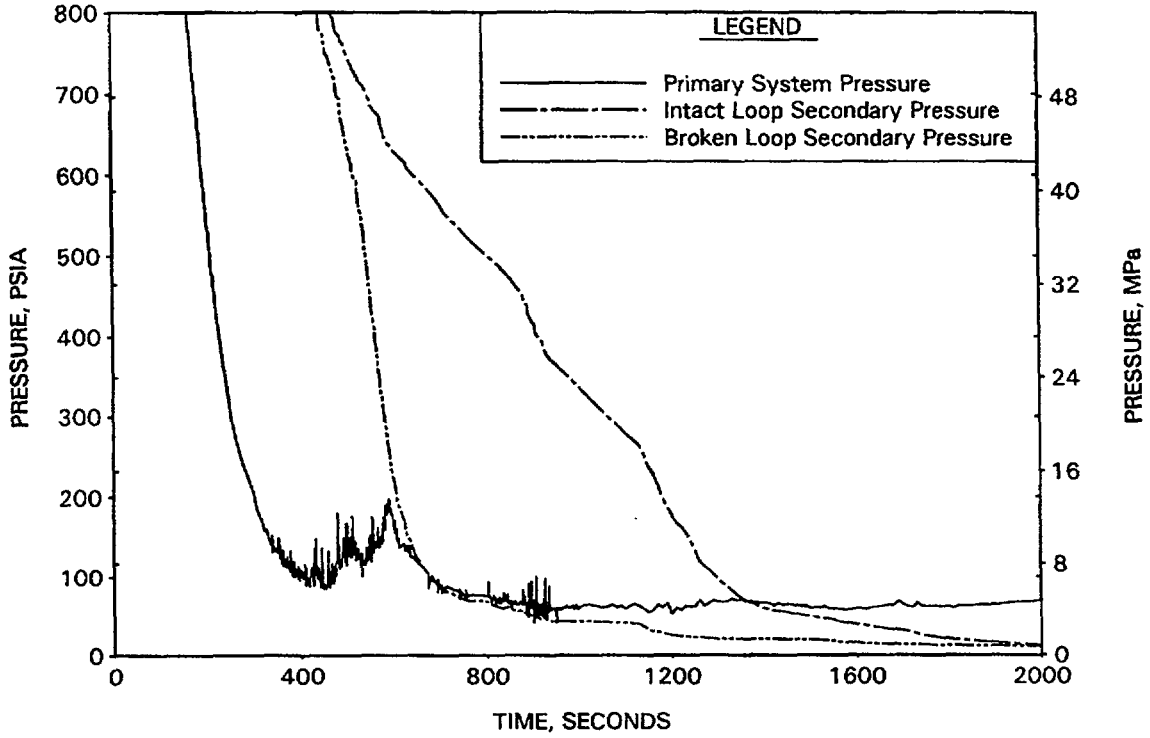


FIGURE A-12. 177-FA Raised-Loop 0.42 Sq ft PZR Surge Line Break
Tube to Shell Temperature & Pressure Differences

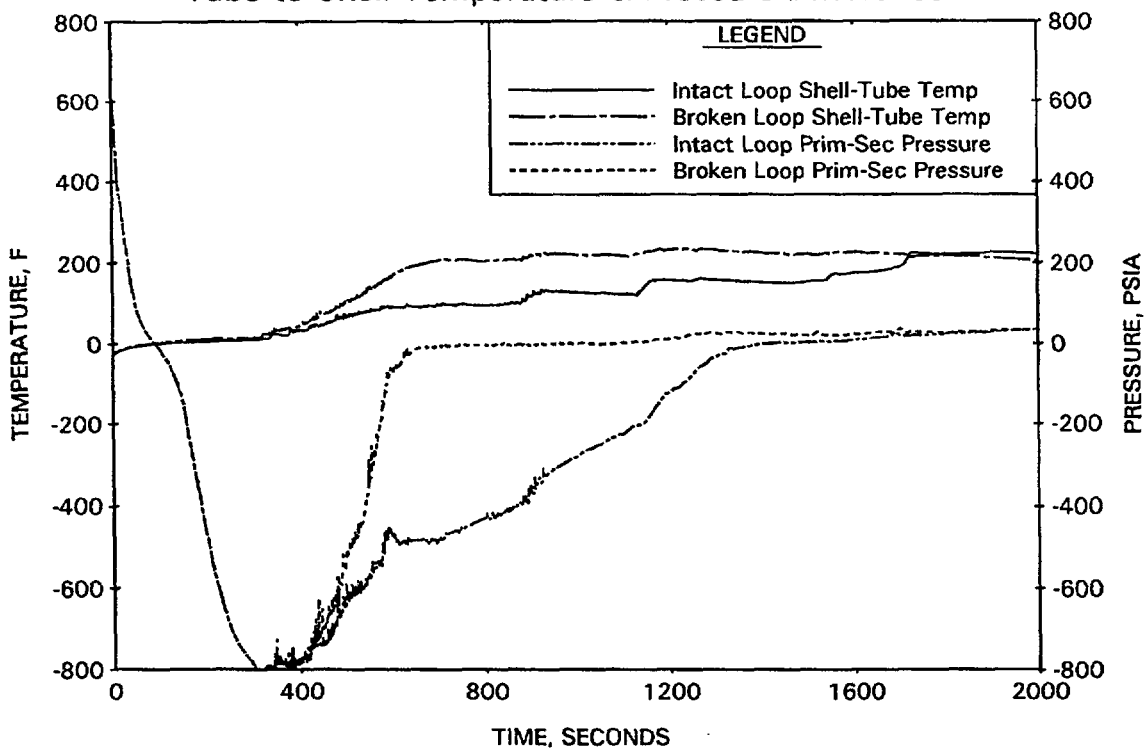


FIGURE A-13. 177-FA Lowered-Loop 0.42 Sq ft PZR Surge Line Break
Broken Loop Shell and Tube Temperatures

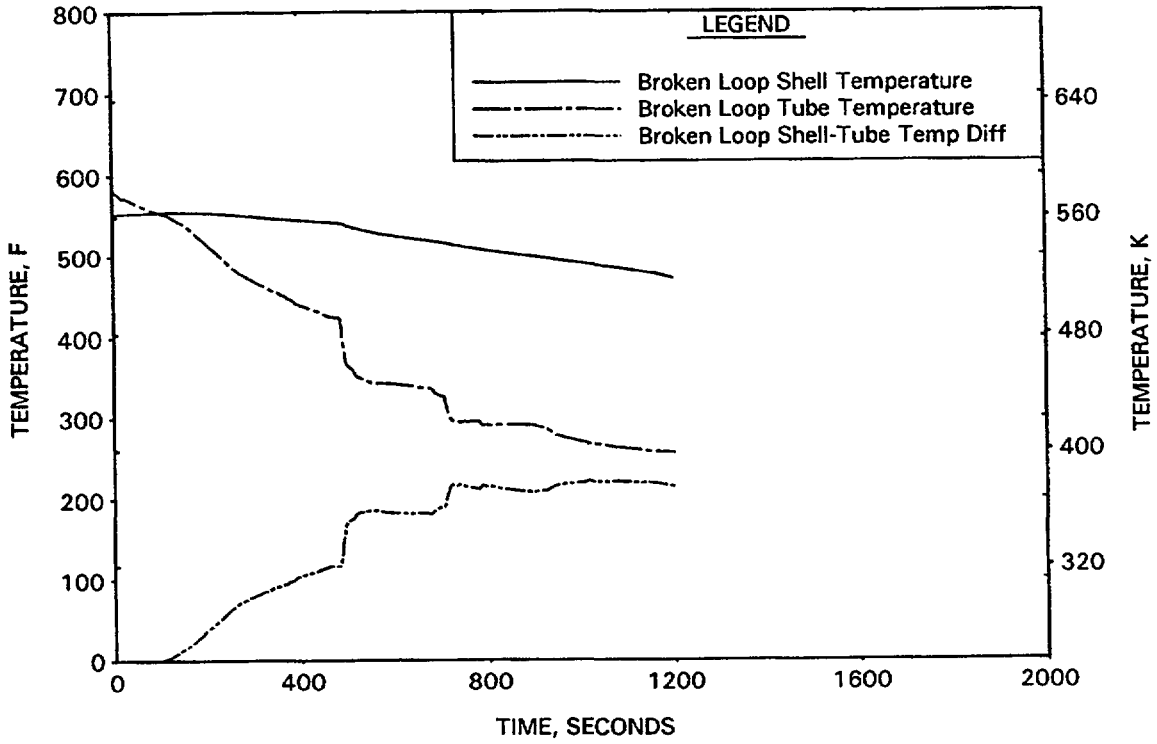


FIGURE A-14. 177-FA Lowered-Loop 0.42 Sq ft PZR Surge Line Break
Intact Loop Shell and Tube Temperatures

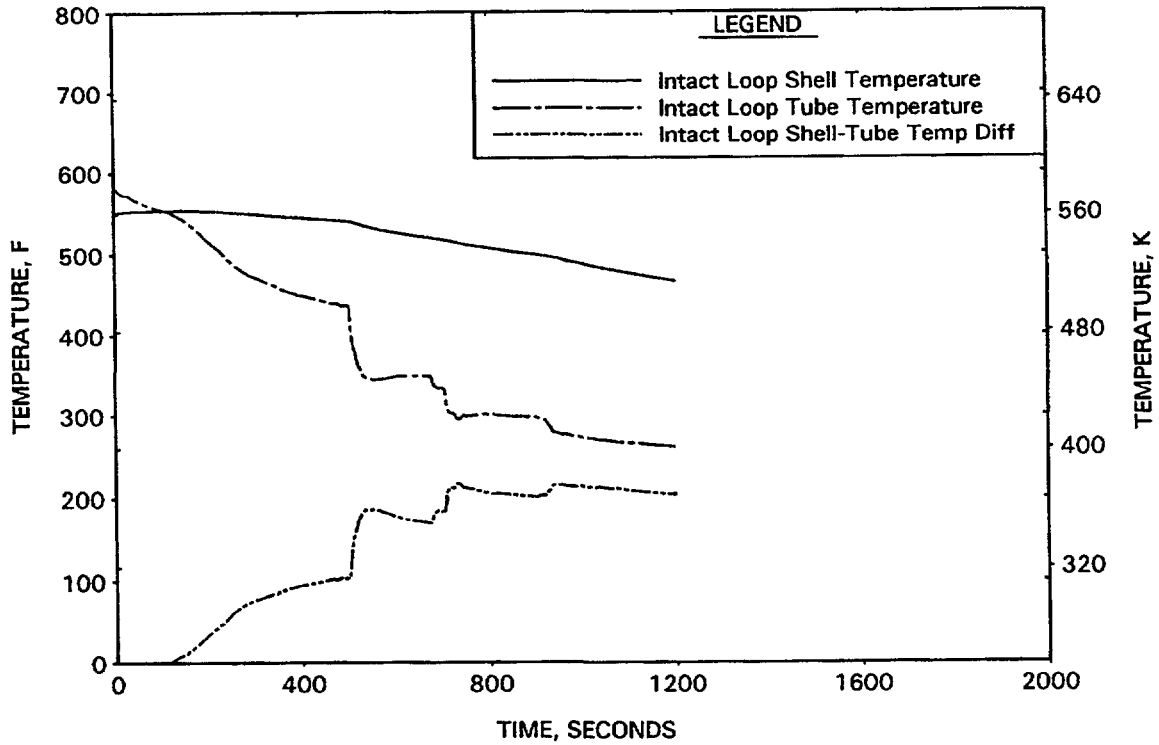


FIGURE A-15. 177-FA Lowered-Loop 0.42 Sq ft PZR Surge Line Break
Primary and Secondary Pressures

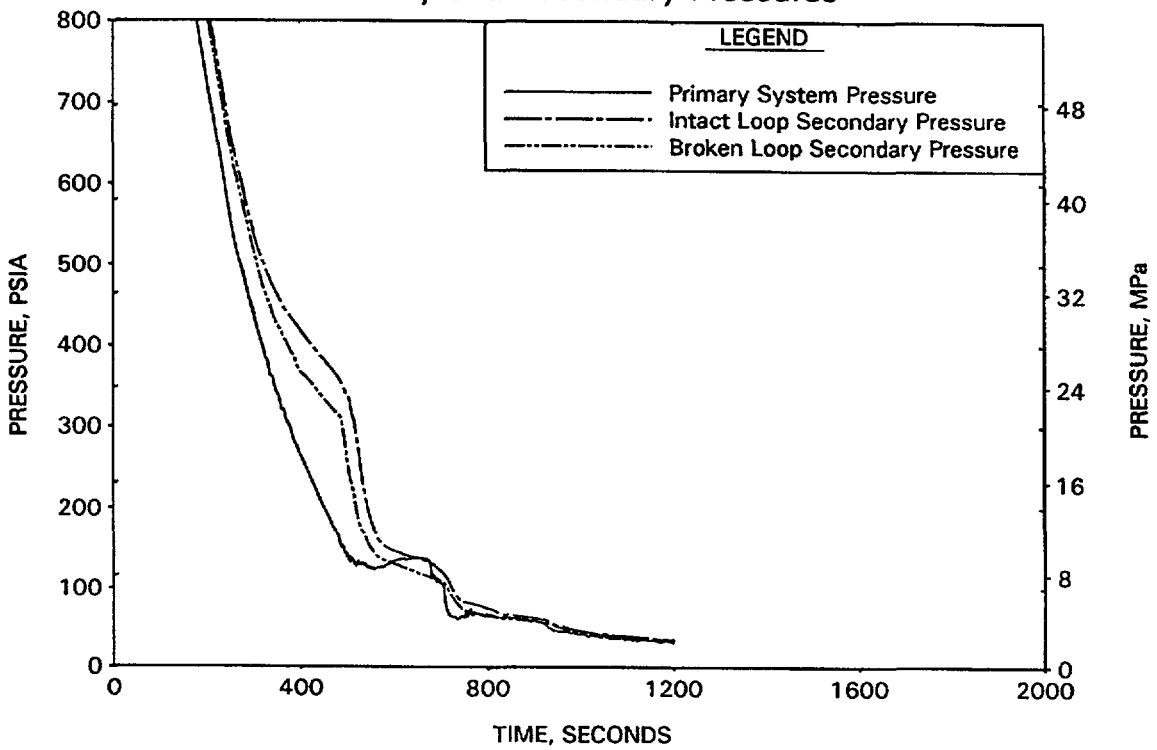


FIGURE A-16. 177-FA Lowered-Loop 0.42 Sq ft PZR Surge Line Break
Tube to Shell Temperature & Pressure Differences

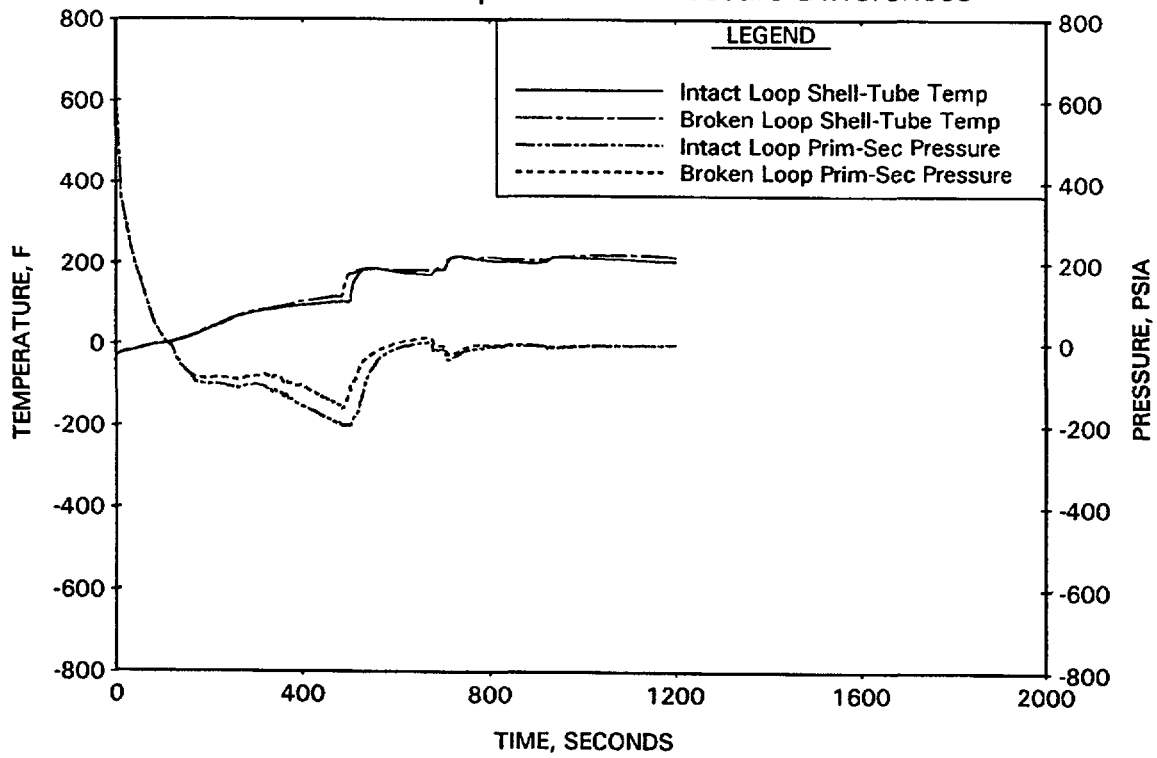


FIGURE A-17. 177-FA Raised-Loop 0.049 Sq ft Upper Head Vent Break
Broken Loop Shell and Tube Temperatures

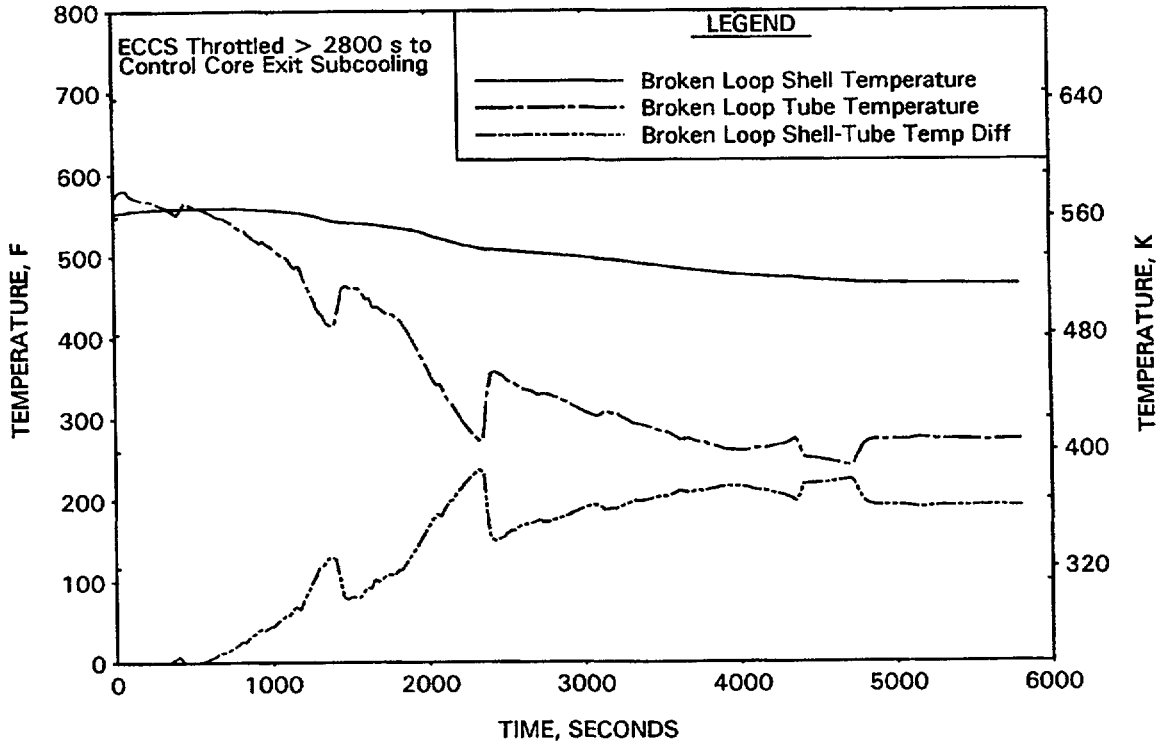


FIGURE A-18. 177-FA Raised-Loop 0.049 Sq ft Upper Head Vent Break
Intact Loop Shell and Tube Temperatures

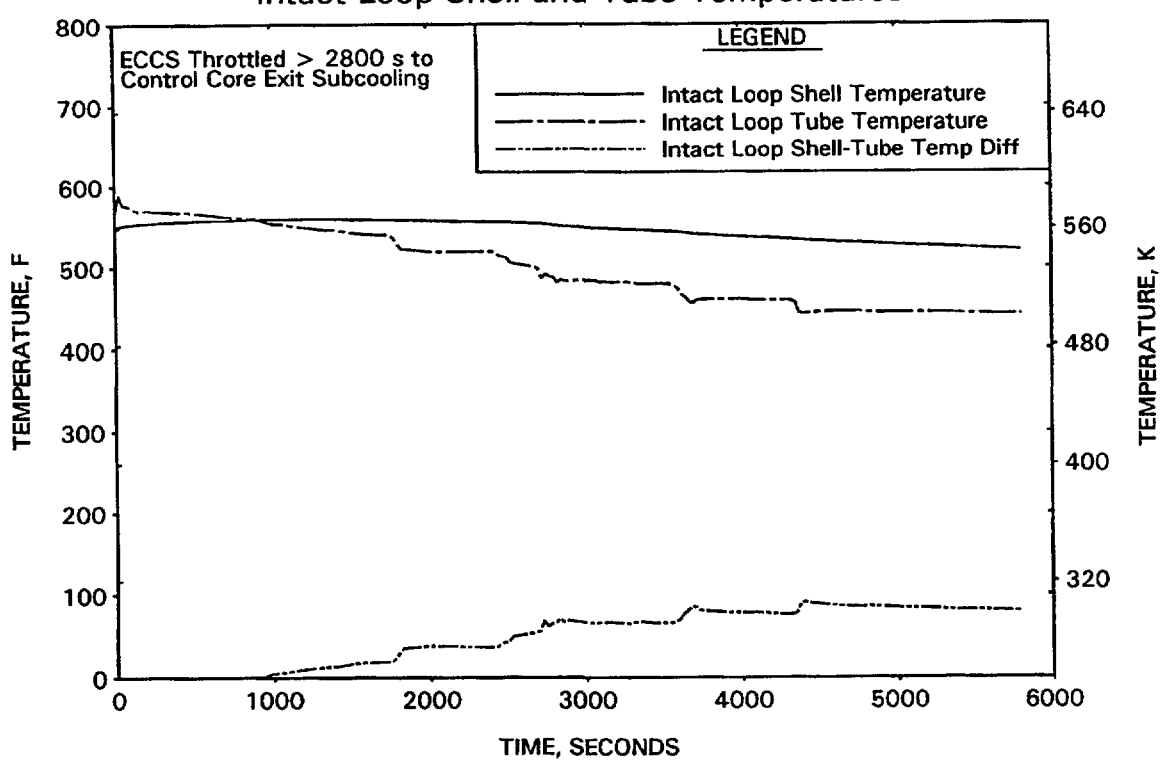


FIGURE A-19. 177-FA Raised-Loop 0.049 Sq ft Upper Head Vent Break
Primary and Secondary Pressures

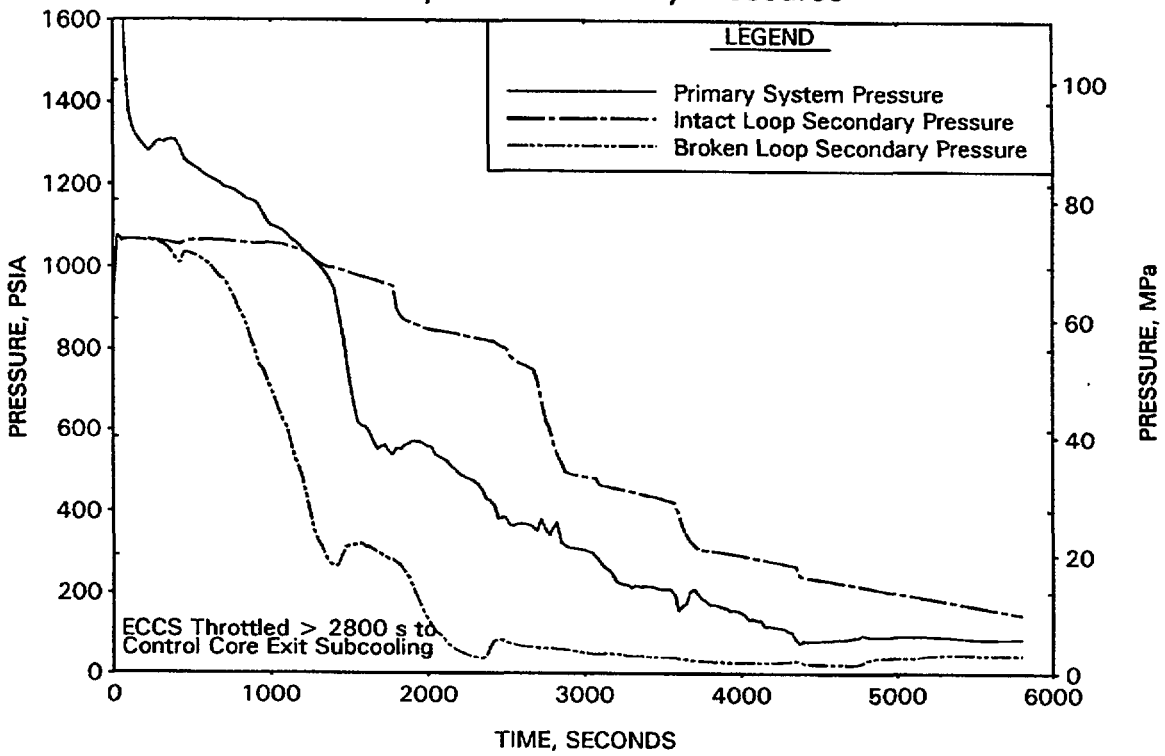


FIGURE A-20. 177-FA Raised-Loop 0.049 Sq ft Upper Head Vent Break
Tube to Shell Temperature & Pressure Differences

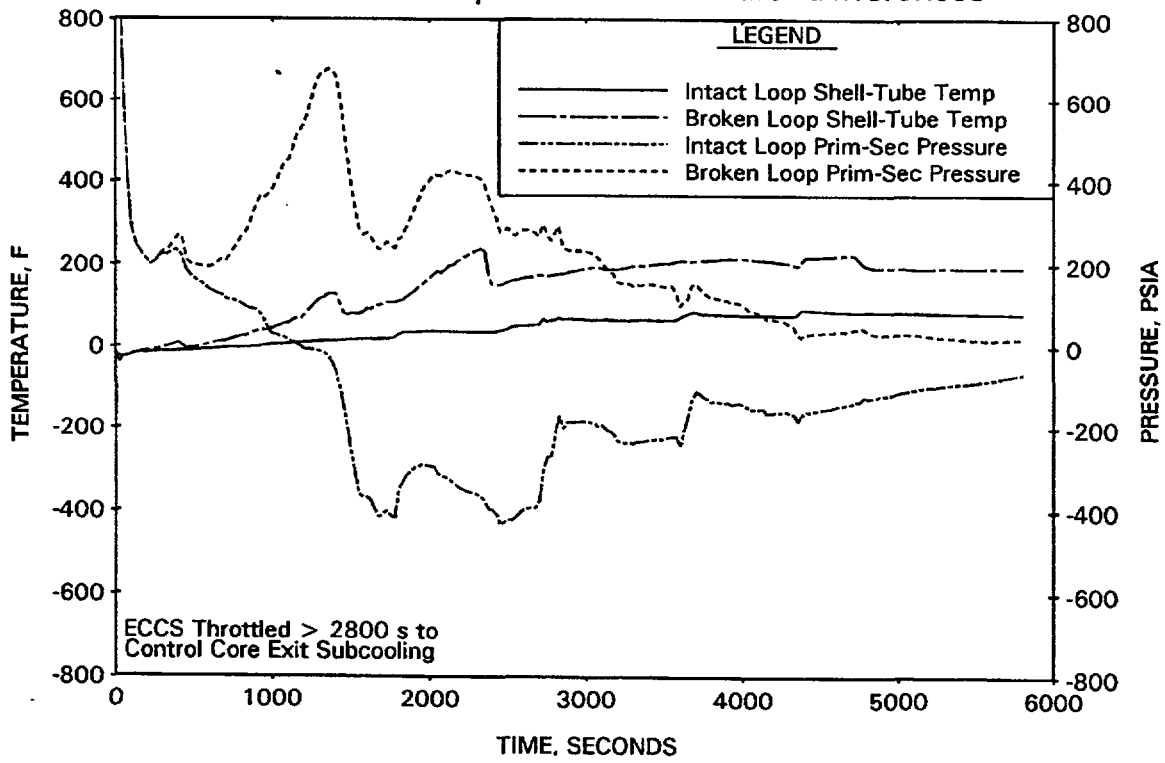


Figure A-21 177-FA Lowered-Loop Plant Estimated Maximum Tube-to-Shell Temperature Differences versus Break Size and Location.

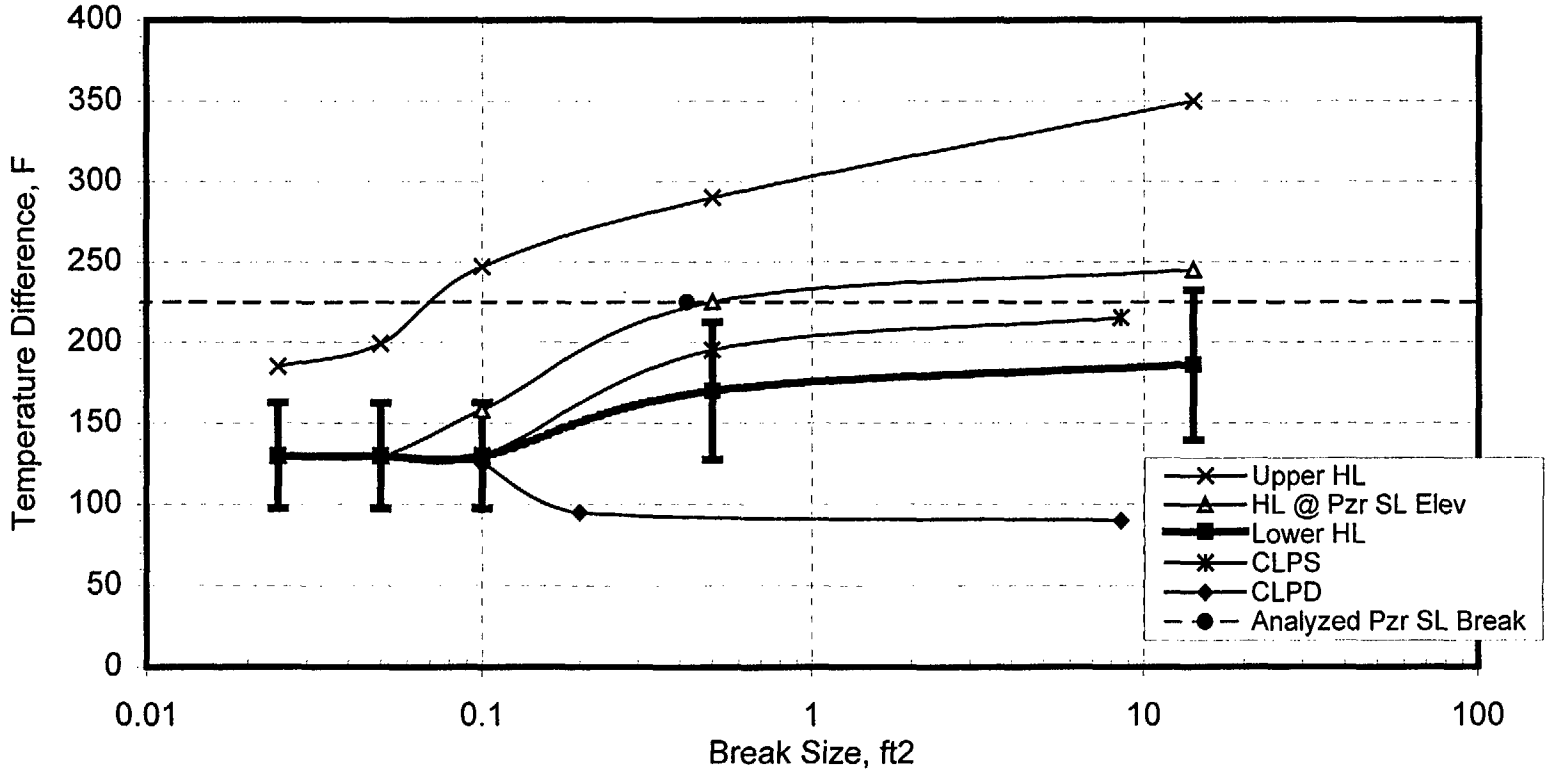
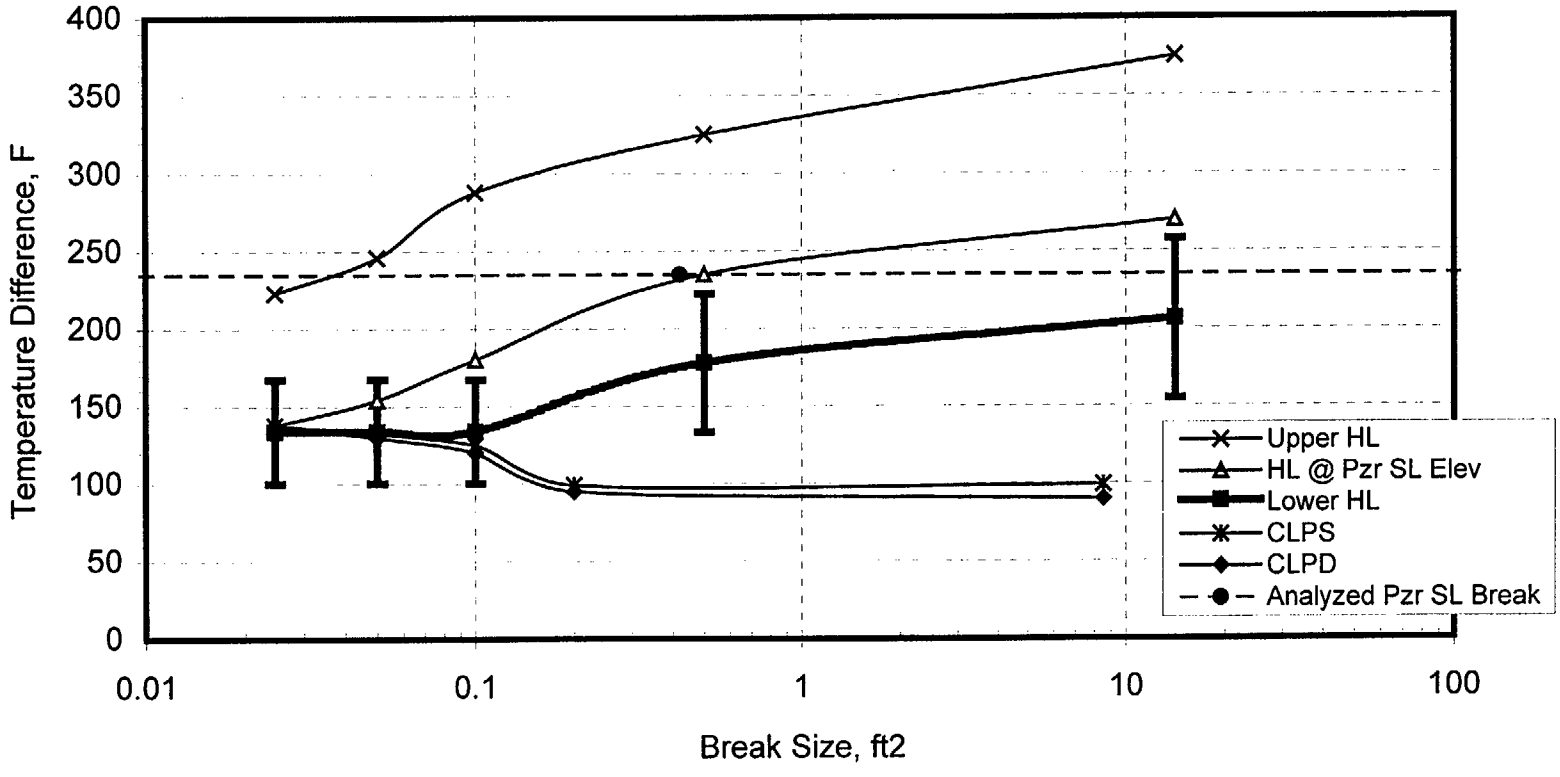


Figure A-22 177-FA Raised-Loop Plant Estimated Maximum Tube-to-Shell Temperature Differences versus Break Size and Location.



Appendix B

Evaluation of Manway/Inspection Opening Failures

Table of Contents

B.1 Physical Description B-3

B.2 Failure Analysis B-4

B.2.1 Installation Process B-7

B.2.2 Stud Wastage B-10

B.3 Conclusion B-11

B.4 References B-11

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 the same 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 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.

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 back plate and gasket) is required to complete a training course on the correct process for removing and installing manway/inspection opening closures. The training

requires developing competency on a mock-up and demonstrating the ability to perform each step of the procedure 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 procedurized 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

The last failure mechanism for one or more studs is loss of material due to boric acid wastage. In the early 1980s, there was an NRC Staff concern about boric acid wastage of studs. 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 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

C.1 Purpose C-3

C.2 RCS Hot Leg Piping -- Scope and Construction C-3

C.3 Hot Leg Piping -- Effects of Aging C-6

C.3.1 Hot Leg Piping -- Clad Carbon Steel Aging Effects C-7

C.3.1.1 Cracking of Ferritic Material Due to Pre-Service or Service-Induced Flaws C-8

C.3.1.2 Loss of Ferritic Material Due to Cladding Cracking C-9

C.3.1.3 Loss of Ferritic Material due to Loss of Cladding Material C-14

C.3.1.4 Loss of Ferritic Material due to Boric Acid Wastage C-16

C.3.1.5 Summary of Applicable Aging Effects C-16

C.3.2 RCS Piping Performance History C-16

C.4 Demonstration of Aging Management C-17

C.4.1 Aging Management Programs C-17

C.4.2 Main Coolant Piping -- Clad Carbon Steel C-19

C.5 Conclusions C-20

C.6 References C-20

List of Figures

Figure C-1 Hot Leg Piping C-21

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, and 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 actions of erosion 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].

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.

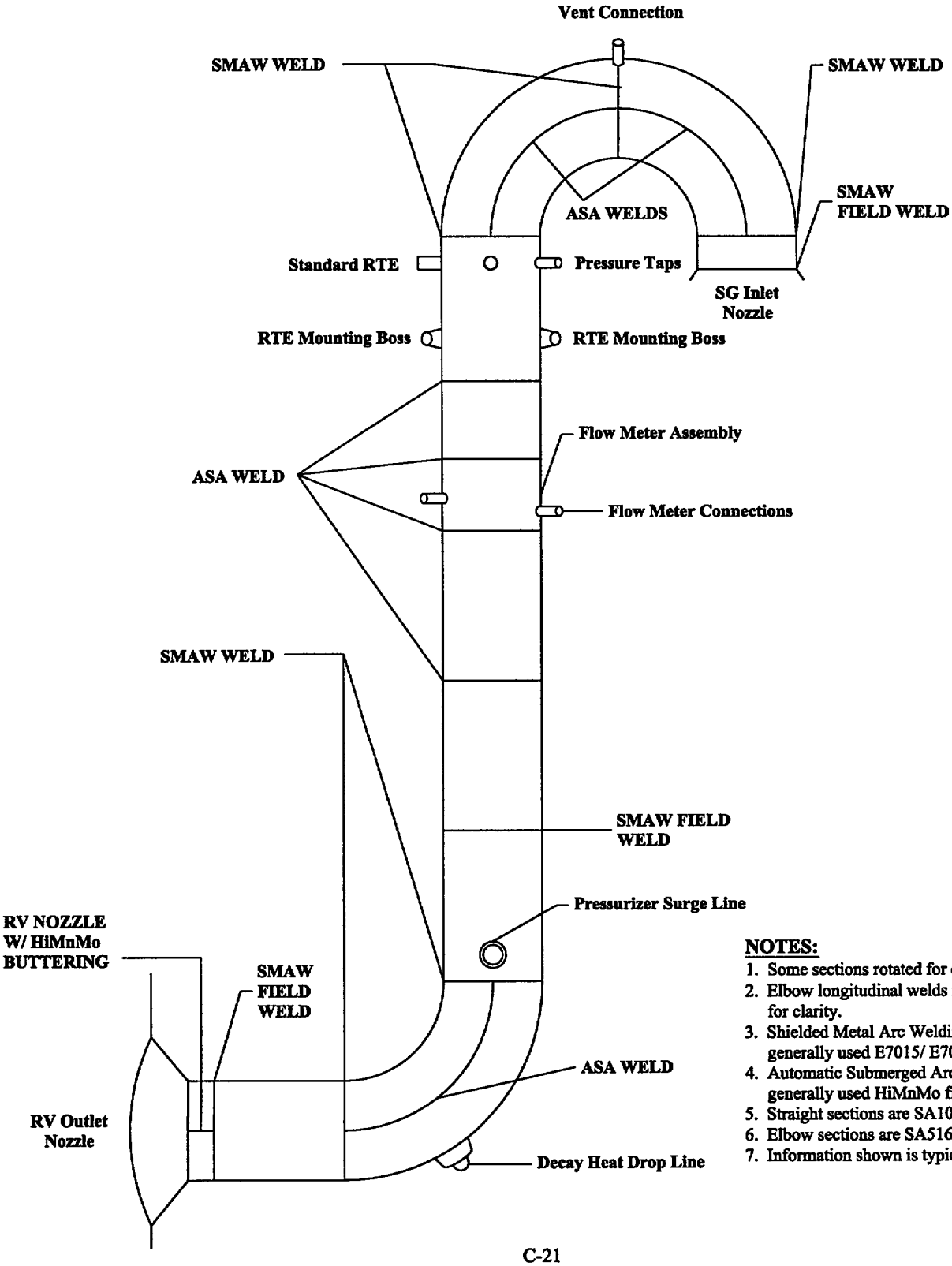
C.6 References

[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

Steam Generator Structural and Leakage Integrity for Postulated Large-Bore RCS Pipe Break

Table of Contents

D.1 Background D-3

D.2 Affected Hardware D-5

D.3 Evaluation of Affected Hardware D-6

D.3.1 Original Tube-To-Tubesheet Rolled Joint D-8

D.3.2 Tube-To-Tubesheet Fillet Weld D-8

D.3.3 Tube-To-Tubesheet Re-Roll Repair D-9

D.3.4 Rolled And Hydraulic Sleeves D-11

D.3.5 Tube Plugs D-12

D.3.6 Tubes With Stabilizers D-13

D.3.7 In-Service Degraded Tubes D-13

D.3.8 Tube-To-Tubesheet Repair Weld D-17

D.4 Conclusion D-17

D.5 References D-18

Steam Generator Structural and Leakage Integrity for Postulated Large-Bore RCS Pipe Break

With input from Framatome Technologies, Inc. (FTI), each of the B&W Owners Group (B&WOG) utilities prepared a plant specific operability assessment for the limiting large-bore reactor coolant system (RCS) pipe break. The operability assessments provided information on both the structural and leakage integrity of the steam generators for the postulated transient. The conclusion of each assessment was that the structural and leakage integrity of the steam generators is not jeopardized as a result of the large-bore RCS pipe break. The purpose of this appendix is to provide a brief summary of those assessments.

D.1 Background

The Leak Before Break (LBB) Safety Evaluation Report (SER) [D-1] eliminated the dynamic effects of the large break loss of coolant accident (LBLOCA) from the design basis of the steam generator. Therefore, no evaluation of the dynamic effects is required. In addition, the dynamic loads do not affect the existing structural design margins.

Per ASME Code criteria, only the primary loads resulting from a faulted event, like LBLOCA, require evaluation. For the postulated large-bore RCS pipe break event, the only primary load for the steam generator is the pressure load. For the postulated event, the pressures in both the primary and secondary sides of the steam generator depressurize from their 100% steady state power values. In addition, the maximum pressures on either the primary side or secondary side of the steam generator for the postulated event are less than the respective design pressures (2500 psig and 1050 psig). For information, the tubesheets were designed for a pressure differential of 2500 psi. The design pressures have been shown to be structurally acceptable in the "Design" condition evaluations

contained in the stress report for the component. In addition, the allowable stresses for a faulted condition evaluation exceed those of the design case. Therefore, the large-bore RCS pipe break pressure loads would not result in a decrease in existing structural design margins.

Per ASME Code criteria, the thermal loads resulting from a faulted event, like LBLOCA, are classified as a secondary stress and as such do not require evaluation. The criterion for secondary stress is that it is self-limiting and will not fail under single load application. The thermal stresses induced on the steam generator shell, heads, and tubesheets are without question secondary stresses. Even the tubesheet deflections and stresses resulting from the axial thermal loads on the tubes are classified as secondary stresses. Therefore, the shell, heads, and tubesheets do not require evaluation for the thermal stresses associated with the postulated large-bore RCS pipe break event.

However, for degraded steam generator tubes, the axial thermal load associated with the postulated large-bore RCS pipe break event may not satisfy the ASME secondary stress classification. This is due to the large strains associated with the tube load and the potential for the strain to concentrate at a flaw in the tube (localized yielding). Since the tube loads associated with the postulated large-bore RCS pipe break are projected to exceed those evaluated in existing tube flaw analyses, it is likely the structural design margins for degraded tubes would be less if the thermal loads for large-bore RCS pipe break are included in the design basis. It is noted that tube failure due to strain concentrations is not a concern in un-degraded tubes since the strains are evenly distributed over the entire length of the tube.

In addition to degraded tubes, due to the potential localized strains and/or potential increase in tubesheet bore dilations associated with the large-bore RCS pipe break, connections of the tube to the tubesheet and associated tube repair hardware may be affected by the event. Therefore, tube repair hardware and their connections to the steam generator must be assessed for the potential impact of the large-bore pipe break.

Based on the preceding discussions, it is concluded that only the structural design margin of degraded tubes, their repair hardware, and the attachments of the tubes to the tubesheet may be affected by a large-bore RCS pipe break. Existing structural design margins for other steam generator pressure boundary components are not affected by the large-bore RCS pipe break event. Therefore, a limited analysis of the impact of a postulated large-bore RCS pipe break event on the structural and leakage integrity of the steam generator tubes and their repair hardware was performed. A summary of the analysis is described below.

It is noted that the required design margins for tubes and repair hardware for the remaining limiting design basis events (i.e., small break LOCA, SLBOCA, and main steam line break, MSLB) will be maintained when the large-bore RCS pipe break event is not included. Therefore, the applicable criteria of Reg. Guide 1.121 [D-2] and the ASME Code will continue to be satisfied for all steam generator (SG) components.

D.2 Affected Hardware

A detailed review of the steam generators and their repair hardware was performed to identify the specific hardware that may be affected by tube loads and dilations caused by the large-bore RCS pipe break. Based on that review, it was concluded that the following items required evaluation or disposition for the effects of large-bore RCS pipe break. The specific items requiring assessment include:

- Original Fabrication Tube-to-Tubesheet Rolled Joint
- Original Fabrication Tube-to-Tubesheet Fillet Weld
- Tube-to-Tubesheet Re-roll Repair
- 80-inch and 31-inch Rolled Mechanical Sleeves, and Oconee Hydraulic Sleeve
- Plugs (Mechanical and Welded)
- Tube Stabilizers

- In-service Degraded Tubes
- Tube-to-Tubesheet Repair Welds

An assessment of the structural and leakage integrity of each of these items was prepared as part of the operability assessments. A summary of the assessments is provided in the following sections.

D.3 Evaluation of Affected Hardware

As previously stated, the assessment evaluated the SG for the effects of the estimated tube loads for a large-bore RCS pipe break event, which may be higher than the previously qualified loads. In addition, the effects of the estimated dilations on joint strength and leakage were assessed. Some general discussion on structural strength and leakage is provided below. Additional discussions are provided in the assessments of the individual items.

TUBE AXIAL LOAD:

The maximum tube axial load resulting from the large-bore RCS pipe break event has been estimated to be approximately 3850 lbs. This load is also similar to the limiting upper tolerance yield load of the OTSG tubing, 3900 lbs. Since the tubes and repair hardware may be exposed to the axial load resulting from a large-bore RCS pipe break, each of the potentially affected items previously defined were assessed for the maximum load. The assessments also took into account the effects of dilations on the strength of attachment joints. It was noted that the higher axial loads may actually improve the joint strength of repair hardware attached to the tube ID because of the compressive hoop stress generated by Poisson's effect in the tube.

TUBE PRESSURE LOAD:

The large-bore RCS pipe break transient results in a reduction of pressure in both the primary and secondary side of the steam generators. When the primary side begins to refill with cold water and cools the tubes creating the large axial loads, the pressure in both the primary and secondary sides is expected to be less than 100 psi. In addition, the pressure difference between the primary and secondary sides (ΔP) is expected to be lower than 100 psi. At the time of maximum tube load and dilation, the ΔP is estimated to be approximately 45 psi. Therefore, there are no significant stresses or dilations resulting from the pressure loads associated with the large-bore RCS pipe break event.

LEAKAGE:

Leakage is a concern for the mechanical joints connecting the tube to the tubesheet and for the joints connecting repair hardware (sleeves and plugs) to the inside diameter of the tubes. The change in dilations between the connecting parts can affect the amount of leakage across the joint. Although leakage is believed to be negligible for the large-bore RCS pipe break event due to the small driving force ($\Delta P < 100$ psi), each of the previously defined items that has a mechanical joint was assessed for potential leakage associated with the dilations. It is important to remember that the estimated dilation used in the assessment was the maximum dilation of any time throughout the transient and that the maximum value occurs for only a very short time. The average dilation over ten or so minutes of transient time would be much lower than the maximum. In addition, the average dilations will reduce further as the transient progresses due to decreasing tube axial loads and dilations. Therefore, the average leakage over a defined period of time will be significantly lower than the peak leak rates calculated below.

The effects of the large-bore RCS pipe break transient loads and dilations on each of the previously defined items are summarized in the sections below.

D.3.1 Original Tube-To-Tubesheet Rolled Joint

The original fabrication tube-to-tubesheet rolled joint provided a 1 inch long (minimum) friction fit between the tube and the tubesheet bore. The rolled tube extended into the portion of the tube outside the tubesheet bore ("tube end stick out") and provided a tight crevice for application of the tube-to-tubesheet weld.

The operability assessments for the rolled joint concluded that there are no structural or leakage concerns associated with rolled joints because the tube-to-tubesheet welds assure the integrity of the tube-to-tubesheet connection. Assessments of the welds are provided in other sections of this appendix. Additionally, the discussions provided in Section D.3.3 pertaining to the re-roll repair also apply to the original tube-to-tubesheet rolled joint.

D.3.2 Tube-To-Tubesheet Fillet Weld

If the original fabrication tube-to-tubesheet rolled joint (or even a repair re-roll) is unable to resist the tube axial load, the load, or more likely a portion of it, would be imposed on the tube-to-tubesheet fillet weld.

The operability assessments used results from ASME Code analysis and testing to conclude that the original shop fabrication fillet welds are capable of resisting the estimated maximum tube axial loads associated with the postulated large-bore RCS pipe break event. The fillet weld stresses exceeded the ASME Code limits for the limiting load from the large-bore RCS pipe break event when using the <u>minimum</u> design dimensions and Code material strengths for the weld. However, load testing of the fillet weld indicates that the weld is capable of withstanding the load from a large-bore RCS pipe break without failure. The conclusion was based on the assumption that the weld was required to resist the entire tube axial load.

D.3.3 Tube-To-Tubesheet Re-Roll Repair

Re-rolling the tube into the tubesheet has been performed to provide a supplemental pressure boundary for portions of tubes contained within the tubesheet that contain flaw indications. To date, re-rolls have only been installed in the upper tubesheets of the steam generators. Therefore, only re-rolls in the upper tubesheet were assessed for the loads and dilations from a large-bore RCS pipe break.

AXIAL STRENGTH:

For the assessment of structural integrity of the rolled joint, it was conservatively assumed that the rolled joint would not be able to resist the large-bore RCS pipe break axial tube load. Therefore, the axial load (or portion of it) would be transmitted to the original fabrication rolled joint and/or to the tube-to-tubesheet weld. Assessments of both the original fabrication fillet weld and repair flush weld were performed and provided evidence that the welds would be capable of carrying the entire load from a large-bore RCS pipe break. The welds also provide a leak tight boundary.

The only joints potentially not covered by the preceding discussion were those which have a significant circumferential flaw above the rolled joint. The concern is that the circumferential flaw could limit the transfer of load from the joint to the weld and could therefore result in the tube slipping within the tubesheet. To date, no re-roll has been installed in a tube with a known complete severance. In addition, calculations of the critical flaw size for circumferential cracks showed that a circumferential flaw must be very large before tube failure would occur (i.e. 60% through-wall with greater than 150 degree extent). Since the majority of the indications in the original roll joint are small axial or small volumetric indications, the potential for tubes to fail (sever) and slip is extremely limited.

Even if a tube were to slip, it would remain within the tubesheet. The amount of tube slippage is limited by the free thermal growth difference between the tube and shell. It was determined that the tube slippage was conservatively limited to approximately one and one-half inches. It was also concluded that there are no real structural concerns for a tube that slips during a large-bore RCS pipe break event. Leakage for a tube that slips is limited by the tight annulus between the tube OD and tubesheet bore and also by the small ΔP associated with the event. Additional discussion on leakage is provided below.

Based on the preceding discussion, it was concluded that it is highly unlikely that a tube would slip as a result of the large-bore RCS pipe break event. Even if a tube or tubes were to slip, the number of tubes should be very small and there would be no additional structural damage resulting from the slipped tube(s).

LEAKAGE:

For all tubes without a through-wall flaw that have an undamaged tube-to-tubesheet weld, leakage across the rolled joints is not a concern because the weld provides a leak tight barrier.

For tubes with through wall flaws, even those that allow the tube to slip, the small ΔP associated with the event limits the leakage. Even if the maximum delta dilations (tubesheet bore dilation minus tube dilation) for the large-bore RCS pipe break are greater than the normal operating values, they occur for only a very short time (a couple of minutes). If the leakage at the time of maximum dilations is several times greater than that experienced during normal operation, the average leakage over an extended period of time (say a couple of hours) would still be much smaller. In addition, the allowable accident leakage is significantly greater than the normal operating allowable leakage. Therefore, if the normal operating leakage is acceptable (limits are not violated), the leakage associated with a large-bore RCS pipe break should also be acceptable.

Although the leakage past a re-rolled joint for the large-bore RCS pipe break event is expected to be negligible due to the small ΔP, a calculation of the maximum leakage (at maximum dilation) for a re-rolled joint in which the tube above it has severed was determined. The leakage was limited by the small annulus between the tube and tubesheet bore. Assuming a limiting delta dilation between the tube and tubesheet bore, and a representative pressure and temperature for the large-bore RCS pipe break event, the limiting leakage was determined to be 0.06 gals/min per severed tube.

Since the likelihood of a severed tube is extremely small, and the leakage associated with a severed tube is relatively small, it was concluded that the structural and leakage integrity of the re-rolls were acceptable for the postulated large-bore RCS pipe break event.

D.3.4 Rolled And Hydraulic Sleeves

All operating OTSGs have a number of 80-inch and/or 31-inch rolled sleeves installed in them. These sleeves were installed primarily as a preventive measure to mitigate the effects of high cycle fatigue along the open tube lane. Some plants have also installed these sleeves to repair tubes with known degradation as an alternative to plugging.

Qualification testing was used to determine the structural and leakage integrity of the sleeves and their attachments to the tubes. The operability assessment determined that the existing qualification testing of the sleeves was applicable for loads associated with the large-bore RCS pipe break event.

For the structural integrity of the sleeve and joint, the minimum failure load of all the sleeves tested was used. The minimum failure load (sleeve slippage) for all the samples tested was 4409 lbs. Since the minimum failure loads exceeded the estimated maximum load of 3850 lbs for large-bore RCS pipe break, it was concluded that the structural integrity of the sleeves and sleeve joints was acceptable.

Due to the small ΔP associated with the large-bore RCS pipe break event, leakage by the sleeve joint will be much lower than the qualification test leakage. Based on the qualification leak rates it was determined that the sleeve leakage associated with large-bore RCS pipe break event is negligible.

In summary, the structural and leakage integrity of the sleeves and sleeve joints is acceptable for the large-bore RCS pipe break event.

D.3.5 Tube Plugs

There are a number of different plug designs installed in the various steam generators. There are welded plugs that are installed by welding the plug to the tubesheet face (cladding) or to the end of the tube. There are explosively welded plugs that are attached to the tube ID. There are also mechanical plugs, both ribbed and non-ribbed, that have been attached to the tube ID by roll or mandrel expansion creating a mechanical interference. Assessments of the various plug designs were performed to determine the effects of the postulated large-bore RCS pipe break event on the structural and leakage integrity of the plugs.

Welded plugs: The operability assessments determined that all welded plugs, including the explosively welded plug, were not significantly affected by the large-bore RCS pipe break event. The conclusions were based on results of analyses and testing which showed the plugs and their welds were able to resist the applicable loads associated with large-bore RCS pipe break event. In addition, the plug with its welded attachment to the tube or tubesheet provides a leak tight pressure boundary. Therefore, the structural and leakage integrity of the welded plugs was concluded to be acceptable for the large-bore RCS pipe break event.

Mechanical Plugs: All operating OTSGs have a number of rolled mechanical plugs installed in them. The plugs are attached by roll expanding the plug into the tube. Therefore, both the plug and plug-to-tube rolled joint were assessed for the effects of the tube axial loads and dilations resulting from the large-bore RCS pipe break event.

Results from analysis and testing were used to justify the structural integrity of the plugs and their attachment (rolled joint) to the tube. Based on those results it was concluded the plug and plug rolled joint are able to resist the applicable loads associated with the large-bore RCS pipe break event.

Leakage integrity of the plug rolled joint was assured by using the results of existing qualification testing. Qualification testing of the plug joint consisted of leak testing at pressure differentials in excess of 2200 psi (compared to an estimated ΔP of less than 100 psi for large-bore RCS pipe break). Using the test leakage values and assuming 10% plugging per steam generator, the total plug leakage was determined to be less than 0.01 gallons per minute. The operability assessments therefore concluded that the leakage integrity of the rolled plugs was acceptable.

D.3.6 Tubes With Stabilizers

Stabilizers are installed in the OTSGs by attaching them to the end of a tube plug. As a result, neither tube axial loads nor tubesheet bow with its resulting tubesheet bore dilations affect the structural integrity of the stabilizer. Therefore, no assessment of the effects of loads and dilations for the large-bore RCS pipe break event was required.

D.3.7 In-Service Degraded Tubes

The potential effects of the postulated tube loads from a large-bore RCS pipe break on the structural integrity of degraded tubes were addressed. Tubesheet bore dilations do not

affect the integrity of the tubes themselves; therefore, no assessment of the dilations was required.

For the operability assessments, three degradation types were considered. They included axial flaws, circumferential flaws, and volumetric flaws. Critical flaw sizes were assessed for both free span and constrained (within tubesheet) tube geometries.

AXIAL FLAWS:

The critical loading for axial flaws is the ΔP (burst pressure) across the tube wall. Since the ΔP used in the existing axial flaw qualifications was significantly greater than that associated with large-bore RCS pipe break event, it was concluded that the existing axial flaw qualifications remain applicable. In addition, the presence of an increased axial tensile load for the large-bore RCS pipe break event may increase the burst pressure due to the compressive hoop stress created by Poisson's effect associated with the axial load. Therefore, the existing tube inspection and repair (plugging) programs assure the structural integrity of the tubes with axial flaws.

The only concern for leakage from axial indications is for those flaws in the tube ends that have been left in service as allowed by the Tube End Cracking Alternative Repair Criteria (TEC ARC). Due to the small ΔP associated with large-bore RCS pipe break, it was concluded that the TEC leakage rates for MSLB were bounding. The plant specific operability assessments concluded that the potential leakage associated with their TECs was acceptable.

For information, flow rates through free span axial cracks of various lengths were also determined. For an assumed ΔP of 45 psi and a fluid temperature of 70°F, the calculated leakage ranged from 2.22×10^{-7} gpm for a 0.05 inch long flaw to 9.50×10^{-3} gpm for a 1.00 inch long flaw.

CIRCUMFERENTIAL FLAWS:

The critical loading for the circumferential flaws is the tube axial load. Since the tube axial tensile load for the large-bore RCS pipe break transient has the potential to exceed those previously analyzed, a new assessment was required.

An evaluation was performed to determine the allowable circumferential extent for a 60% through-wall (TW) flaw for the limited axial tube loads associated with tube yield strengths (lower tolerance yield load of 2900 lbs, average yield load of 3400 lbs, and upper tolerance yield load of 3900 lbs). The evaluation determined the circumferential extent at which net section collapse is expected to occur.. It is noted that the upper tolerance yield load of 3900 lbs is slightly greater than the estimated maximum load of 3850 lbs for the large-bore RCS pipe break. The flow stress associated with the yield stress used in the limiting load calculation is also used in determining the critical flaw size for that load.

The results of the analysis showed that for the limiting load of 3900 lbs, the allowable extent of a 60% through-wall flaw was 80 degrees for a free-span flaw and 150 degrees for a flaw constrained by the tubesheet. It was determined that existing tube inspections are capable of finding flaws of this magnitude. Therefore, the existing tube inspection and repair (plugging) programs assure the structural integrity of the tubes with circumferential flaws.

Since flaws with circumferential extent are repaired on detection, leakage for the flaw itself is not a concern. Leakage for the "repaired" tube is conservatively assumed to be controlled (limited) by the repair process. That is, even if the detected flaw is not through wall, or very small, the leakage for the tube is based on leakage past the repair product. Some examples of repair products include hydraulic expansions in the tubesheet (TMI), plugs, sleeves, and re-rolls.

Although it is unlikely that a large flaw could go undetected and grow through wall, flow rates through free span circumferential cracks of various lengths were determined. For an assumed ΔP of 45 psi and a fluid temperature of 70°F, the calculated leakage ranged from 2.00×10^{-4} gpm for a 0.05 inch long flaw to 1.47 gpm for a 0.90 inch long (circumferential extent of ~165 degrees) flaw.

VOLUMETRIC FLAWS:

Volumetric flaws are caused by IGA and wear and are best described as uniform thinning. An evaluation was performed to determine the allowable TW percent for uniform thinning defects. The limiting tube yield loads of 2900, 3400, and 3900 lbs were used as the applied loads. The equivalent material ultimate stress at the assumed temperature of 200F was used as the allowable stress. The allowable thinning for a flaw extent of 360 degrees was determined to be 52%, 48%, and 44% TW for the three respective tube loads. Although the ΔP is negligible for the large-bore RCS pipe break event, the critical flaw size for internal pressure of 2575 psi was evaluated and found to be less limiting than the axial load case.

IGA can produce flaws that affect a significant portion of the tube circumference, although most are confined to an area of 90° or less. This damage mechanism is not limited to a particular elevation or region of the steam generator. IGA is typically detected with bobbin coil examination, except in the lower tubesheet crevice region, where rotating coil technology is also used.

Based on in situ pressure tests and laboratory examinations of IGA flaws, it was concluded that the IGA flaws are unlikely to leak.

SUMMARY OF DEGRADED TUBE ASSESSMENT:

In summary, plant specific operability assessments determined that the critical flaw sizes would be detected with standard SG tube inspection equipment. Therefore, the structural and leakage integrity of the degraded tubes is ensured by established inspection criteria.

D.3.8 Tube-To-Tubesheet Repair Weld

Tube-to-tubesheet repair welds have been installed in the upper tubesheet of the A-OTSG at Oconee Unit 1 and in the B-OTSG at CR-3. The repair welds were required to replace the original fabrication fillet weld that had been damaged by loose parts.

The operability assessments made use of a comparative analysis of the original fabrication fillet weld and the repair weld to conclude that the original fillet weld is bounding. Since the fillet weld was shown to be capable of resisting the loads associated with the large-bore RCS pipe break, the repair fillet welds are also acceptable for the large-bore RCS pipe break loads.

D.4 Conclusion

A plant specific operability assessment was prepared by each of the B&WOG utilities to evaluate the effects of a large-bore RCS pipe break event on the structural and leakage integrity of their steam generators. Based on the results of the individual assessments, it was concluded that the structural and leakage integrity of the steam generators is acceptable for the large-bore RCS pipe break event.

D.5 References

[D-1] 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.

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

Appendix E

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

E.1 Purpose E-3

E.2 Background E-3

E.3 Review and Evaluation E-4

E.3.1 Regulatory Basis E-4

E.3.2 Methodology E-5

E.3.3 GDC Specifying LOCAs E-5

E.3.4 NRC-Cited GDC E-8

E.3.5 Remaining GDC E-9

E.4 Conclusion E-10

E.5 References E-11

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

E.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 a request from the existing Babcock & Wilcox-type nuclear power plants to not include large-bore reactor coolant system (RCS) piping break thermal-hydraulic loads in the licensing basis for the once-through steam generators (OTSGs).

E.2 Background

All operating Babcock & Wilcox-type plants were licensed based on the results of Topical Report BAW-10027 [E-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 LBLOCA loads. However, repair methods have also been qualified without considering the LBLOCA loads, using small break LOCA (SBLOCA) loads and MSLB loads as the repair qualification loads. In approving the qualification of the repair methods, the NRC typically cited in their Safety Evaluations that General Design Criterion (GDC) 14, "Reactor Coolant Pressure Boundary," and draft Regulatory Guide (RG) 1.121 [E-2], "Bases for Plugging Degraded PWR Steam Generator Tubes," were satisfied. 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 Babcock & Wilcox Owners Group (B&WOG) has prepared this risk-informed Topical Report that provides for not including postulated breaks in large-bore RCS piping in the design for both existing and replacement OTSGs. Use of this Topical Report will be limited to the OTSGs. 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 to not include the large-bore pipe break loads in the existing plants' OTSG design.

E.3 Review and Evaluation

E.3.1 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 [E-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.

E.3.2 Methodology

To evaluate the need for an exemption as if the GDC of 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.

E.3.3 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 not including large-bore pipe break thermal-hydraulic loads in the licensing basis for OTSGs.

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.

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.

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.

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.

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.

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.

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.

E.3.4 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, also, an extremely low risk due to a gross rupture of the OTSG tubes. 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.

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 are OTSG loads resulting from "loss of coolant accidents" and not from "normal operation" as addressed by the GDC. Therefore, this GDC is not a candidate for a 10 CFR 50.12 exemption.

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.

E.3.5 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 postulated accident of a break in a large-bore piping of the Reactor Coolant System is of very low frequency and, therefore, need not be postulated in the OTSG design.

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.

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.

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.

E.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 not including large-bore pipe break thermal-hydraulic loads as part of the OTSG licensing basis. 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 a request from the B&WOG to not include large-bore pipe break thermal-hydraulic loads as part of the OTSG licensing basis.

E.5 References

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

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

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

Appendix F

Glossary of Acronyms

ADV	Atmospheric Dump Valve
ASME	American Society of Mechanical Engineers
ARC	Alternative Repair Criteria
ASA	Automatic Submerged Arc
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
BWST	Borated Water Storage Tank
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
CFT	Core Flood Tank
CL	Cold Leg
CLPD	Cold Leg Pump Discharge
CLPS	Cold Leg Pump Suction
CR	(NRC) Circular (Generic Communication)
CR-3	Crystal River Unit 3
DHDL	Decay Heat Drop Line
EAL	Emergency Action Level
ECCS	Emergency Core Cooling System
EFW	Emergency Feedwater
EM	Evaluation Model
EOP	Emergency Operating Procedure
EPRI	Electric Power Research Institute
FA	Fuel Assembly

FTI	Framatome Technologies, Inc.
GDC	General Design Criteria
GL	(NRC) Generic Letter (Generic Communication)
GLRP	Generic License Renewal Program
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
LBB	Leak-Before-Beak
LBLOCA	Large Break Loss of Coolant Accident
LERF	Large Early Release Frequency
LL	Lowered-Loop
LLNL	Lawrence Livermore National Laboratory
LOCA	Loss of Coolant Accident
LPI	Low Pressure Injection
MFW	Main Feedwater
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
NRC	Nuclear Regulatory Commission
NUREG	NRC Report
OD	Outer Diameter
ONS-1	Oconee Nuclear Station-1
OTSG	Once-Through Steam Generator
PNNL	Pacific Northwest National Laboratory
PRA	Probabilistic Risk Assessment
PT	Penetrant Testing
PWHT	Post-Weld Heat Treatment
PWR	Pressurized Water Reactor
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
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
SSCs	Systems, Structures or Components
SMAW	Shielded Metal Arc Welding
TBV	Turbine Bypass Valve
TEC	Tube End Cracking
TMI-1	Three Mile Island-1
TW	Through-Wall
UT	Ultrasonic Testing