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James T. Reilly
Vice President

June 27, 2008

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

Subject:

Docket Nos. 50-361 and 50-362
Amendment Application Numbers 252 and 238
Proposed Change Number NPF-10/15-583
Replacement Steam Generators
San Onofre Nuclear Generating Station, Units 2 and 3

References:

1. Nuclear Energy Institute Technical Specification Task Force (TSTF) Traveler, TSTF-449, "Steam Generator Tube Integrity" Revision 4, with corresponding Nuclear Regulatory Commission announcement in the Federal Register on May 6, 2005 (70 FR 24126) of availability of TSTF-449, as part of the consolidated line item improvement process (CLIIP)

2. Letter from N. Kalyanam (NRC) to Richard M. Rosenblum (SCE) dated September 19, 2006; Subject: San Onofre Nuclear Generating Station, Units 2 and 3 – Issuance of Amendments Re: Technical Specification Improvement Regarding Steam Generator Tube Integrity Based on Technical Specification Task Force (TSTF) Standard Technical Specification Change Traveler, TSTF-449, "Steam Generator Tube Integrity" (TAC Nos. MC9236 and MC9237)

3. Letter from N. Kalyanam (NRC) to Richard M. Rosenblum (SCE) dated November 9, 2006; Subject: San Onofre Nuclear Generating Station, Units 2 and 3 – Issuance of Amendments Re: Change, Define the Extent of the Required Tube Inspections, and Repair Criteria Within the Tubesheet Region of the Steam Generators (TAC Nos. MC8850 and MC8851)

Dear Sir or Madam:

Pursuant to 10CFR50.90, Southern California Edison (SCE) hereby requests the following amendment to operating licenses NPF-10 and NPF-15 for the San Onofre Nuclear Generating Station (SONGS), Units 2 and 3, respectively to revise Technical Specifications (TSs) 3.4.17, "Steam Generator (SG) Tube Integrity," 5.5.2.11, "Steam

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Generator (SG) Program," 5.5.2.15, "Containment Leakage Rate Testing Program," and 5.7.2.c, "Special Reports."

These proposed changes consist of Proposed Change Number 583 (PCN-583) and are in support of the replacement of the steam generators (SGs) at SONGS Units 2 and 3. The proposed changes reflect revised SG inspection and repair criteria and revised peak containment post-accident pressure resulting from installation of the replacement SGs.

Use of analysis codes for evaluation of the design and installation of the RSGs was limited to those analysis codes currently described in the Updated Final Safety Analysis Report (UFSAR) with the following two exceptions.

- For stress analysis of the RSG external shell and internals, the ABAQUS code was used in lieu of the ANSYS code
- For evaluation of the post-tensioned containment structure, the ANSYS code was used in lieu of the FINEL code. This evaluation accounts for removal and restoration of concrete and tendons to provide the temporary containment opening.

The replacement SGs (RSGs) are to be installed during the Unit 2 Fuel Cycle 16 refueling outage (2C16), currently scheduled to begin in October 2009, and the Unit 3 Fuel Cycle 16 refueling outage (3C16), currently scheduled to begin in October 2010.

In 2006, SCE adopted Reference 1 by NRC-issued Amendments (References 2 and 3) for Units 2 and 3. The proposed changes related to SG inspection and repair reflect criteria that are specific to the Replacement Steam Generators, but, with the exception of the proposed steam generator tube plugging criterion, will maintain consistency of the SONGS Units 2 and 3 TSs with Reference 1. Please note that the calculation of the proposed steam generator tube plugging criterion is not yet complete. The proposed tube plugging criterion of 35% is a preliminary value. SCE will provide confirmation or a corrected value when the calculation is approved.

SCE has determined that there are no significant hazards considerations associated with the proposed change and that the change is exempt from environmental review pursuant to the provisions of 10 CFR 51.22 (c)(9).

The Enclosure to this letter provides the Description and No Significant Hazards Analysis for the proposed amendment.

The proposed amendment is neither exigent nor emergency. SCE requests approval of this license amendment request (LAR) no later than September 1, 2009, to support preparations for the first SG replacements during the Unit 2 Cycle 16 refueling outage, which is currently scheduled to begin in October 2009. SCE requests the license amendment(s) be made effective upon NRC issuance, to be implemented for Unit 2 prior to entry into Mode 4 during the Unit 2 Cycle 16 refueling outage return-to-service and to be implemented for Unit 3 prior to entry into Mode 4 during the Unit 3 Cycle 16 return-to-service.

A list of regulatory commitments resulting from this application is provided in the Enclosure.

Should you have any questions, or require additional information, please contact Ms. Linda Conklin at (949) 368-9443.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on June 27, 2008
(Date)

Sincerely,

Enclosure:
Proposed Change Number (PCN)-583
- Attachment A: Existing Pages, SONGS Unit 2
- Attachment B: Existing Pages, SONGS Unit 3
- Attachment C: Proposed Pages, Redline and Strikeout, SONGS Unit 2
- Attachment D: Proposed Pages, Redline and Strikeout, SONGS Unit 3
- Attachment E: Proposed Pages, SONGS Unit 2
- Attachment F: Proposed Pages, SONGS Unit 3
- Attachment G: Proposed Bases Pages, SONGS Unit 2, for information only
- Attachment H: Proposed LCS Pages, SONGS Unit 2, for information only
- Attachment I: Proposed Pages, SONGS Unit 3, with changes from PCN-582 and PCN-583

cc: E. E. Collins, Regional Administrator, NRC Region IV
N. Kalyanam, NRC Project Manager, SONGS Units 2 and 3
G. G. Warnick, NRC Senior Resident Inspector, SONGS Units 2 and 3
S. Y. Hsu, California Department of Public Health, Radiologic Health Branch

ENCLOSURE

Description and No Significant Hazards Analysis
for Proposed Change NPF-10/15-583
San Onofre Nuclear Generating Station
Units 2 and 3

LICENSEE'S EVALUATION

DESCRIPTION AND NO SIGNIFICANT HAZARDS ANALYSIS FOR PROPOSED CHANGE NPF-10/15-583 PROPOSED TECHNICAL SPECIFICATION CHANGE, REPLACEMENT STEAM GENERATORS

San Onofre Nuclear Generating Station Units 2 and 3

EXISTING TECHNICAL SPECIFICATIONS

Unit 2: see Attachment A
Unit 3: see Attachment B

PROPOSED TECHNICAL SPECIFICATIONS

(highlight for additions, strikeout for deletions)

Unit 2: see Attachment C
Unit 3: see Attachment D

PROPOSED TECHNICAL SPECIFICATIONS

(with changes)

Unit 2: see Attachment E
Unit 3: see Attachment F

PROPOSED TECHNICAL SPECIFICATION BASES/LICENSEE CONTROLLED SPECIFICATIONS

(Provided for information / highlight for additions, strikeout for deletions)

Unit 2 Bases: see Attachment G (typical for both Units 2 and 3)
Unit 2 LCS: see Attachment H (typical for both Units 2 and 3)

PROPOSED TECHNICAL SPECIFICATIONS

(with changes from PCN-582 and PCN-583)

Unit 3: see Attachment I

1.0 INTRODUCTION

Changes are proposed to San Onofre Nuclear Generating Station (SONGS) Units 2 and 3 Technical Specifications (TSs) in support of replacement steam generators (RSGs) to be installed during the Unit 2 Fuel Cycle 16 refueling outage (2C16), currently scheduled to begin in October 2009, and the Unit 3 Fuel Cycle 16 refueling outage (3C16), currently scheduled to begin in October 2010. The proposed changes are associated with steam generator (SG) inspection and repair and a revision to the peak containment post-accident pressure.

For the changes to the SG inspection and repair criteria, the affected Technical Specification (TS) Sections are:

- 3.4.17, "Steam Generator (SG) Tube Integrity"
- 5.5.2.11, "Steam Generator (SG) Program"
- 5.7.2.c, "Special Reports"

This proposed change will maintain consistency of the SONGS Units 2 and 3 TSs with NRC-approved Technical Specification Task Force (TSTF) Traveler, TSTF-449, "Steam Generator Tube Integrity," Revision 4, when the original SGs are replaced by the RSGs. The availability of TSTF-449 was announced in the Federal Register on May 6, 2005 (70 FR 24126), as part of the consolidated line item improvement process (CLIIP). Subsequently, the TSs for the original SGs were made consistent with TSTF-449 by NRC-issued Amendments for SONGS Unit 2 (204 and 206) and for SONGS Unit 3 (196 and 198).

For the change to the peak containment post-accident pressure, the affected Technical Specification is 5.5.2.15, "Containment Leakage Rate Testing Program."

Technical Specifications Bases and Licensee Controlled Specifications changes to implement these proposed Technical Specifications changes are included for information only.

2.0 PROPOSED CHANGES

<u>SG Tube Inspection and Repair</u>

SCE proposes the following revisions to TSs 3.4.17, 5.5.2.11, and 5.7.2.c to provide applicable requirements when the original SGs are replaced by the RSGs:

- Delete the existing SG tube repair method (sleeving), including sleeve inspection, sleeve repair criteria, and associated reporting that do not apply to the RSGs.
- Delete the existing alternate repair criteria that do not apply to the RSGs.
- Replace the existing tube repair criterion of 44%, which does not apply to the RSGs, with the RSG tube repair criterion of 35%*.
- Replace the inspection requirements for the existing Alloy 600 mill annealed tubing with the inspection requirements applicable to the RSG Alloy 690 thermally treated tubing.

*This proposed criterion is a preliminary value. SCE will provide confirmation or a corrected value when the calculation is approved. Hereafter the notation (preliminary) is used.

Specific revisions to these TSs are described below.

SCE proposes to revise TSs 3.4.17, 5.5.2.11.a, and 5.7.2.c to delete the terms "or repair" and "or repaired."

SCE proposes to revise TS 5.5.2.11.c.1 which currently states:

> "Tubes shall be plugged or repaired if the non-sleeved region of a tube is found by inservice inspection to contain flaws with a depth equal to or exceeding 44% of the nominal tube wall thickness, at a location that is not addressed in Technical Specification 5.5.2.11.c.2."

The new wording will be:

> "Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 35% (preliminary) of the nominal wall thickness shall be plugged."

SCE proposes to delete TSs 5.5.2.11.c.2, 5.5.2.11.c.3, and 5.5.2.11.c.4.

SCE proposes to revise TS 5.5.2.11, which states in part:

> "In addition to meeting the requirements of d.1, d.2, d.3, and d.4 below ..."

The existing phrase will be replaced by the following:

> "In addition to meeting the requirements of d.1, d.2, and d.3 below ..."

Also a Note and a sentence about sleeving are deleted.

SCE proposes to revise TS 5.5.2.11.d.2 which currently states:

> "Inspect 100% of the tubes at sequential periods of 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the SGs. No SG shall operate for more than 24 effective full power months or one refueling outage (whichever is less) without being inspected. "

The new wording will state:

> "Inspect 100% of the tubes at sequential periods of 144, 108, 72, and thereafter, 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the SGs. In addition, inspect 50% of the tubes by the refueling outage nearest the midpoint of the period and the remaining 50% by the refueling outage nearest the end of the period. No SG shall operate for more than 72 effective full power months or three refueling outages (whichever is less) without being inspected."

SCE proposes to delete TSs 5.5.2.11.d.4, 5.5.2.11.f, 5.7.2.c.8, and 5.7.2.c.9.

<u>Peak Containment Post-Accident Pressure</u>

SCE proposes to revise TS 5.5.2.15, "Containment Leakage Rate Testing Program," to change the peak containment post-accident pressure. Currently, TS 5.5.2.15 states:

> "The calculated peak containment internal pressure related to the design basis loss-of-coolant accident, P_a, is 45.9 psig (P_a will conservatively be assumed to be equal to the calculated peak containment internal pressure for the design basis Main Steam Line Break (56.5 psig) for the purpose of containment testing in accordance with this Technical Specification."

In support of the planned replacement of steam generators at SONGS Units 2 and 3, both the design basis loss-of-coolant accident and the design basis Main Steam Line Break accident have been re-analyzed. Following replacement of SGs, the calculated peak containment internal pressure related to the design basis loss-of-coolant accident will be 48.0 psig, while the calculated peak containment internal pressure related to the design basis Main Steam Line Break accident will be 51.5 psig. As a result, SCE proposes to revise TS 5.5.2.15 to state:

> "The calculated peak containment internal pressure related to the design basis loss-of-coolant accident, P_a, is 48.0 psig (P_a will conservatively be assumed to be equal to the calculated peak containment internal pressure for the design basis Main Steam Line Break (51.5 psig) for the purpose of containment testing in accordance with this Technical Specification."

<u>Technical Specifications Bases and Licensee Controlled Specifications</u>

In order to implement these proposed changes, various TS bases and LCS sections will also need to be revised. Markups of revised TS Bases and LCS pages for Unit 2 are provided for information only.

<u>Contents of the Application</u>

This enclosure contains a description of the proposed changes, the supporting technical analyses, and the no significant hazards consideration determination. Attachments A through F contain existing, marked-up, and retyped TS pages. Attachments G and H provide marked-up TS Bases and Licensee Controlled Specification (LCS) pages, respectively, for information only. The changes to the affected TS Bases will be incorporated in accordance with the TS Bases Control Program (TS 5.4). Similarly, the changes to the affected LCS will be incorporated in accordance with the provisions of 10CFR50.59.

On September 30, 2007, SCE submitted amendment application 236 for Unit 3, which is a separate request to revise TS 5.5.2.15 to extend the interval for the Integrated Leak Rate Test (ILRT). Attachment I provides a clean version of the Unit 3 TS 5.5.2.15 showing both the changes from this proposed change and SCE's previous request (Amendment Application 236) to extend the interval for the ILRT.

3.0 BACKGROUND

SONGS Units 2 and 3 currently have Combustion Engineering designed and manufactured SGs (referred to as the existing, or original SGs) installed in both units. New Mitsubishi Heavy Industries (MHI) designed and manufactured RSGs will be installed during the Unit 2 Fuel Cycle 16 refueling outage (2C16), currently scheduled to begin in October 2009, and the Unit 3 Fuel Cycle 16 refueling outage (3C16), currently scheduled to begin in October 2010. Since the existing SGs and RSGs are similar, the SG replacement is being evaluated under 10 CFR 50.59.

The applicable regulatory requirements and guidance associated with the proposed changes to SG Tube inspection and repair criteria are addressed by the NRC Notice of Availability published on May 6, 2005 (70 FR 24126), the NRC Notice for Comment published on March 2, 2005 (70 FR 10298), and TSTF-449, Revision 4.

The changes to the SG design that affect the SG Tube inspection and repair criteria are:

- The tube repair method of sleeving is not applicable to the RSGs
- Replacing Alloy 600 mill-annealed tubing with Alloy 690 thermally treated tubing
- Use of hydraulic expansion of tubes into the tubesheet instead of explosive expansion of tubes in the tubesheet

The changes to the SG design that affect the peak containment post-accident pressure are:

- Use of a flow restrictor in the RSG steam outlet nozzle
- Changes in the primary and secondary inventories
- Changes to the SG tube heat transfer surface area

To determine the limiting peak containment post-accident pressure, mass and energy release analyses for the design basis Loss-of-Coolant Accident (LOCA) and Main Steam Line Break (MSLB) were performed. The mass and energy releases from these re-analyses were then used as input to the containment response analyses for the design basis LOCA and MSLB. These analyses used existing SONGS analysis methodology while accounting for the differences between the RSGs and the existing steam generators.

4.0 TECHNICAL ANALYSIS

4.1 STEAM GENERATOR TUBE INSPECTION AND REPAIR CRITERIA

4.1.1 Justification

SCE proposes the following revisions to TSs 3.4.17, 5.5.2.11, and 5.7.2.c to provide applicable tube inspection and repair requirements when the original SGs are replaced by the RSGs:

- Delete the existing SG tube repair method (sleeving), including sleeve inspection, sleeve repair criteria, and associated reporting that do not apply to the RSGs.
- Delete the existing alternate repair criteria that do not apply to the RSGs.
- Replace the existing tube repair criterion of 44%, which does not apply to the RSGs, with the RSG tube repair criterion of 35% (preliminary).
- Replace the inspection interval requirements for the existing Alloy 600 mill annealed tubing with the inspection interval requirements applicable to the RSG Alloy 690 thermally treated tubing.

Specific technical analyses of these proposed revisions are described below.

TSs 3.4.17, 5.5.2.11, and 5.7.2.c are revised to delete the existing SG tube repair method (sleeving), including sleeve inspection, sleeve repair criteria, and associated reporting. The review and acceptance of this repair method is based on the specific configuration of the existing SGs, including the Alloy 600 mill annealed tubes and explosive tube expansion in the tubesheet. The RSGs have an improved configuration, including Alloy 690 thermally treated tubes and hydraulic tube expansion in the tubesheet. The existing review and acceptance of this repair method is not valid for the improved configuration of the RSGs. Therefore, this repair method is required to be deleted from TSs for the RSGs. Deletion of this repair method applicable to the existing SGs will ensure that for the RSGs, all tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 35% (preliminary) of the nominal tube wall thickness will be plugged as required by revised TS 5.5.2.11.c.1 and SG Tube Integrity TS Surveillance Requirement (SR) 3.4.17.2.

TS 5.5.2.11.c.4 is deleted to delete the existing SG tube alternate repair criteria (ARC). The existing ARC is commonly referred to as C*, which recognizes the contribution to structural and leakage integrity provided by the explosive expansion of the tubing within the tubesheet. The technical basis, review and acceptance of this ARC is based on the specific configuration of the existing SGs, including the Alloy 600 mill annealed tubing and explosive tube expansion in the tubesheet. The RSGs have an improved configuration, including Alloy 690 thermally treated tubes and hydraulic tube expansion in the tubesheet. The existing technical basis, review and acceptance of this ARC are not valid for the improved configuration of the RSGs. Deletion of this ARC applicable to the existing SGs will ensure that for the RSGs, all tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 35% (preliminary) of the nominal tube wall thickness will be plugged as required by revised TS 5.5.2.11.c.1 and SG Tube Integrity TS SR 3.4.17.2.

TS 5.5.2.11.c.1 is revised to replace the existing tube repair criterion of 44%, that does not apply to the RSGs, with the RSG tube repair criterion of 35% (preliminary). The technical basis, review and acceptance of the existing tube repair criterion of 44% is based on the specific configuration of the existing SGs. A tube repair criterion of 35% (preliminary) is applicable to the RSGs.

TS 5.5.2.11.d.2 is revised to replace the inspection requirements for the existing Alloy 600 mill annealed tubing with the inspection requirements applicable to the RSG Alloy 690 thermally treated tubing. This will provide applicability for the RSGs (that have an improved tubing material), while maintaining consistency with regulatory guidance on these TSs. The RSG tubing material is Alloy 690 thermally treated, that is more resistant to stress corrosion cracking. This proposed TS change will maintain consistency with NRC-approved Technical Specification Task Force (TSTF) Traveler, TSTF-449, "Steam Generator Tube Integrity", Revision 4. TSTF-449 addressed different tubing materials by providing an alternative text selection for each material. The SONGS Units 2 and 3 original and replacement SG tubing materials are specifically addressed in TSTF-449, with an alternative text selection for each material. The availability of TSTF-449 was announced in the Federal Register on May 6, 2005 (70 FR 24126), as part of the consolidated line item improvement process (CLIIP). NRC-issued Amendments for SONGS Unit 2 (204 and 206) and for SONGS Unit 3 (196 and 198) made the TSs for the original SGs consistent with TSTF-449. This revision provides a way to maintain consistency of the TSs with TSTF-449, when the original SGs are replaced by the RSGs.

To support this proposed change for TSs 3.4.17, 5.5.2.11, and 5.7.2.c, SCE has reviewed the safety evaluation (SE) published in the Federal Register on March 2, 2005 (70 FR 10298), as part of the TSTF-449 CLIIP Notice for Comment. This included the NRC staff's SE, the information provided to support TSTF-449, and the changes associated with Revision 4 to TSTF-449. SCE has concluded that the justifications presented in the TSTF-449 SE prepared by the NRC staff regarding inspection requirements for Alloy 690 thermally treated SG tubing are applicable to the SONGS Units 2 and 3 RSGs, and justify incorporation of the requirements for Alloy 690 thermally treated SG tubing in the SONGS Units 2 and 3 TSs for the RSGs.

4.1.2 Summary

The proposed TS 3.4.17, 5.5.2.11, and 5.7.2.c revisions remove the repair method (sleeving), and ARC. The revisions replace the 44% tube repair criterion applicable to the original SGs, with a 35% (preliminary) tube repair criterion applicable to the RSGs. The revisions replace inspection requirements applicable to the tubing material of the original SGs with inspection requirements applicable to the tubing material of the RSGs, thus maintaining consistency with applicable material-specific regulatory guidance (TSTF-449, Revision 4). Overall, these revisions will ensure that all RSG tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 35%

(preliminary) of the nominal tube wall thickness will be plugged as required by revised TS 5.5.2.11.c.1.

The TS 5.5.2.11.b SG structural integrity, accident induced leakage, and operational leakage performance criteria are unchanged and will continue to be met for the RSGs. Meeting the SG performance criteria provides reasonable assurance that the SG tubing will remain capable of maintaining reactor coolant pressure boundary integrity throughout each operating cycle and in the unlikely event of a design basis accident.

4.2 CONTAINMENT PEAK PRESSURE

4.2.1 Objective

An evaluation determined the impact of the replacement steam generators (RSGs) on the SONGS Units 2 and 3 UFSAR (Reference 7.2-1) Section 6.2 containment design basis analyses and provides input to evaluations of equipment required to mitigate accidents that challenge the containment structure.

The RSGs will result in an increase in the stored energy in the primary and secondary systems. Following a loss-of-coolant accident (LOCA), the increased stored energy will result in an increase in the containment pressure and temperature. Following a main steam line break (MSLB) the increased stored energy would typically result in an increase in the containment pressure and temperature. However, each RSG steam outlet nozzle is fitted with a flow restrictor which reduces the energy release rate and causes the peak pressure and temperature for the RSG MSLB event to be lower than with the original steam generator (OSG) MSLB event.

Breaks in the main feedwater piping would result in blowdown that is less limiting than the MSLB. Effective break areas for the main feedwater line break (MFWLB) are limited by the steam generator internals design. Fluid enthalpy for the MFWLB is less than the enthalpy of the fluid in the MSLB, therefore MFWLBs are not analyzed.

The following sections describe the RSG containment analysis, including how its assumptions, design input, methodology, and results compare with the OSG containment analysis.

4.2.1.1 Containment Safety Function and Supporting Safety Systems

The containment encloses the primary and portions of the secondary plant and is the final barrier against the release of fission products in the event of an accident. Design basis events are analyzed to demonstrate that the containment structure can withstand the pressure and temperature conditions resulting from LOCAs and MSLBs inside the containment and that the equipment needed to mitigate these events remains functional both during and following the events.

Condensation of steam on the structures inside containment plays a major role in limiting the containment pressure increase. In addition, automatic Reactor Protective System (RPS) and engineered safety feature (ESF) actuations occur in response to pipe breaks inside containment. The following is an overview of these automatic actions.

When containment pressure exceeds the containment pressure high (CPH) setpoint (5.0 psig analysis value, plus a time delay for actuation signal processing), the following automatic signals are initiated:

- Reactor trip – trips the reactor and terminates at-power operation.

- Safety injection actuation signal (SIAS) – adds borated water to the Reactor Coolant System (RCS) and also initiates a 10 second (± 2.5 sec) sequencer to start the containment spray (CS) pumps but does not open the CS block isolation valves.

- Containment isolation actuation signal (CIAS) – isolates non-essential lines penetrating the containment and closes the main steam isolation valves (MSIVs), the main feedwater isolation valves (MFIVs), and the main feedwater block valves (which functionally serve as backup to the MFIVs).

- Containment cooling actuation signal (CCAS) – actuates containment emergency air cooling units (ECUs) to reduce containment pressure and temperature. The ECUs start approximately 5 seconds after the associated Component Cooling Water (CCW) pump starts to prevent water-hammer in the cooling coils. Each containment emergency air cooling train consists of two coolers or ECU fan units.

When containment pressure exceeds the containment pressure high-high (CPHH) setpoint (20.0 psig analysis value, plus a time delay for actuation signal processing), the following automatic actuation signal is initiated: Containment Spray Actuation Signal (CSAS) initiates the opening of containment spray isolation block valves, which will reduce containment pressure and temperature by the injection of cold spray water.

The Safety Injection System and the Containment Spray System initially take suction from the refueling water storage tank (RWST). When the water level in the RWST is lowered to a certain elevation, the recirculation actuation signal (RAS) is generated and the source of water for the high-pressure safety injection (HPSI) pumps and the CS pumps transfers to the containment emergency sump (CES). In addition, component cooling water flow is directed to the shutdown cooling heat exchangers to provide cooling to the containment spray water. The terms RAS and post-RAS operation describe the conditions when the HPSI and CS pumps draw suction from the containment emergency sump, and when the component cooling water removes heat from the shutdown cooling heat exchanger.

4.2.1.2 Impact of the RSGs on the Design Basis Analyses

As discussed in the following sections, the RSGs differ in many respects from the OSGs (e.g., greater water volume on the primary and secondary sides, higher secondary side operating pressure, steam flow restrictor devices installed in the RSG outlet nozzles, greater heat transfer area, larger metal mass). These differences affect the post-accident challenges to the containment (e.g., peak pressure and temperature, the environmental conditions experienced by equipment required to mitigate the events). The following section describes the LOCA and MSLB analyses that were performed to demonstrate the adequacy of the safety system settings and the safety system performance.

4.2.2 Regulatory Basis

The SONGS Units 2 and 3 UFSAR (Reference 7.2-1) describes adherence to the General Design Criteria (GDC) published as Appendix A to 10 CFR 50 (Reference 7.2-2). GDC 16, 38, and 50 (Containment Design, Containment Heat Removal and Containment Design Basis) are potentially impacted by the proposed RSG changes. In addition, SONGS Units 2 and 3 must meet the requirements of 10 CFR 50.49 regarding the qualification of electrical equipment required to remain functional during and following design basis events. Analyses were performed to demonstrate that the proposed plant configuration with the RSGs meets all applicable criteria. Specifically, the following criteria are used to judge the acceptability of these analyses:

1. GDC 16 requires that a reactor containment and associated systems shall be provided to establish an essentially leak tight barrier to assure that the containment design conditions important to safety are not exceeded for as long as the conditions require. GDC 50 requires that the reactor containment structure, including access openings, penetrations, and the containment heat removal system, shall be designed so that the containment structure and its internal components can accommodate, without exceeding the design leakage rate and with sufficient margin, the calculated pressure condition resulting from a LOCA (or MSLB). Per Standard Review Plan 6.2.1.1.A [Reference 7.2-3], to satisfy the requirements of GDC 16 and GDC 50, the maximum post-accident containment pressure is less than the design pressure of 60 psig (UFSAR Table 6.2-3).

2. The maximum post-accident containment liner temperature is less than the design temperature of 300°F (UFSAR Table 6.2-3). Technical Specification (TS) Bases B3.6.5 clarifies that the temperature limit of 300°F is not a vapor temperature limit, but rather pertains to the containment structure such as the containment liner plate and concrete.

3. The containment heat removal system will reduce the post-accident containment pressure and temperature to a low level following an accident and maintain this low level thereafter. UFSAR Sections 6.2.1.1.1.4, 6.2.2.1.1C and 6.2.2.2.1A,

state that the containment emergency fan cooler system, in conjunction with the Containment Spray System (CSS) and the shutdown heat exchangers (i.e., one train of each system), is capable of reducing the post-LOCA containment pressure from the peak value to one half peak value in 24 hours in accordance with GDC 38 (Reference 7.2-2) and Standard Review Plan 6.2.1.1.A (Reference 7.2-3).

4. The equipment that must function to mitigate the design basis accidents within the containment is qualified to operate under the resulting environmental conditions. Per UFSAR Section 6.2.2.1.3, the design temperature of equipment subjected to LOCA or MSLB conditions is 300°F. Per UFSAR Table 6.2-34 the emergency cooling unit (ECU) atmosphere design inlet temperature is 300°F.

4.2.3 LOCA Containment Analysis

The design differences between the OSGs and RSGs have an effect on the containment response to a LOCA. The following changes have the most impact:

1. The additional RSG RCS inventory due to the larger steam generator (SG) tube bundle increases the mass transferred to the containment during RCS blowdown.

2. The additional RSG secondary side SG inventory results in additional energy transferred to the containment for cold leg breaks.

4.2.3.1 Overall Approach

Consistent with the original design analyses, the mass and energy released into containment during the LOCA event has been calculated. This information was then used for the calculation of the transient containment pressure/temperature response.

The methodology used in this evaluation is identical to the methodology used in the current licensing basis evaluation of the SONGS Units 2 and 3 (Reference 7.2-1). Only input parameters have been updated.

The methodology used in this evaluation and the methodology used in the current licensing basis evaluation are consistent with the methodology identified in the NRC's Standard Review Plan (SRP) (Reference 7.2-3), except for a conservative deviation in the modeling of the carryout rate fraction used in calculating liquid entrainment in the exiting steam flow during the reflood and post-reflood phases of the LOCA. This deviation is addressed in Section 4.2.3.2.1 of this submittal, and in current UFSAR Section 6.2.1.3.4 (Reference 7.2-1).

4.2.3.2 Methodology Used for LOCA Containment Analysis

The LOCA containment analysis was performed in two parts. The CEFLASH-4A and FLOOD3 computer codes calculated the mass and energy discharged from the RCS into the containment. This information was used to calculate the containment response using the COPATTA computer code. This subsection provides both an overview of the analysis methodology and a summary of the important analysis inputs and results. Table 4.2-1 provides an overview of the significant input parameters for the mass and energy calculations and the LOCA containment response calculation.

4.2.3.2.1 LOCA Mass and Energy Analysis Overview

The LOCA mass and energy analysis was performed using methods that were consistent with the methodology described in UFSAR Section 6.2 (Reference 7.2-1). The analytical simulation of the LOCA event is initiated from full thermal power, including measurement uncertainty, and is characterized by four distinct phases – blowdown, reflood, post-reflood and long-term cooldown phase. These phases, and the methodology used to analyze them, are described in the following paragraphs.

Blowdown Phase

The LOCA mass and energy analysis for the blowdown phase was performed using methods that were consistent with the methodology described in UFSAR Section 6.2 (Reference 7.2-1). UFSAR Section 6.2.1.3.3 states that the LOCA blowdown phase is simulated with the CEFLASH-4A code. This UFSAR section also specifically describes some aspects of the CEFLASH-4A code modeling

The LOCA causes a rapid depressurization of the RCS, which quickly falls below the shut-off heads of the HPSI and LPSI pumps. The safety injection pumps are the primary source of core cooling for the majority of the event and will start in response to a SIAS on CPH signal or a pressurizer pressure low signal. As an additional conservatism, flow from the safety injection pumps is omitted during the blowdown phase. Once RCS pressure falls below the pressure in the safety injection tanks (SITs), the SIT check valves will open and SIT water will be discharged into the RCS.

The blowdown phase of the LOCA is simulated using the NRC-approved CEFLASH-4A code methodology (Reference 7.2-5). The use of the CEFLASH-4A code to calculate mass and energy releases from postulated RCS pipe ruptures is discussed in UFSAR Section 6.2.1.3 (Reference 7.2-1). CEFLASH-4A is also used for the 10 CFR 50 Appendix K ECCS performance analysis. However, many input and nodalization changes are made for this application relative to the Appendix K model to ensure that the mass and energy analysis is biased conservatively. This additional conservatism is addressed via the following inputs and assumptions.

- The Appendix K model for fuel clad swelling and rupture was not used. The lack of clad swelling and rupture results in more fuel stored energy being transferred to the RCS coolant.

- Except for conditions of single-phase steam, calculations of heat transfer from core to coolant assumed nucleate boiling even though conditions may warrant departure from nucleate boiling. This biases the prediction such that the energy transfer to the exiting RCS coolant is enhanced.

- RCS volume was conservatively calculated based on the expansion of the reactor loop from cold to hot operating conditions (rated thermal power plus uncertainty) as it results in more mass and energy being discharged into the containment during blowdown. This differs from the Appendix K assumption of using nominal (cold) volumes.

- Time-dependent main feedwater addition was used to account for the hot feedwater added to the steam generators (SGs). This results in more energy on the secondary side of the SGs that must be transferred to the containment.

- Since the containment mass and energy release does not require the radial detail to track the stored energy in the hot assembly, a less detailed core nodalization was used (1 radial region and 5 axial regions).

- The decay heat used during this portion of the analysis was the ANS 5 - 1971 (+20 percent) decay heat standard.

Reflood and Post-Reflood Phases for Cold-Leg Breaks

The LOCA mass and energy analysis for the core reflood and post-reflood phase was performed using methods that are consistent with the methodology described in UFSAR Section 6.2 (Reference 7.2-1). UFSAR Section 6.2.1.3.4 states that the LOCA core reflood and post-reflood phase is simulated with the FLOOD3 code. This UFSAR section also specifically describes some aspects of the FLOOD3 code modeling.

Following the initial blowdown, the reactor is first refilled by the incoming safety injection flow, including SITs, and then reflooded as the core becomes quenched. The effect of the SGs on the mass and energy transferred to containment is important for cold-leg breaks after blowdown because the exiting steam passes through the SGs prior to exiting the RCS to the containment. The addition of SG energy to the break flow may cause the peak containment pressure response to occur during the reflood or post-reflood phase.

The refill phase (the time period during which the reactor vessel fills with safety injection liquid to the bottom of the active core) is conservatively omitted for containment calculations.

The next phase of the transient simulation is the reflood phase, which is defined as the time period during which the coolant accumulating in the reactor vessel increases from the bottom of the active core to two feet below the top of the active core. At this point, the core is considered to be quenched and the liquid entrainment reduces significantly.

The rate of energy release to the containment is biased conservatively by considering the heat transfer from the core to the reactor coolant to be always in the nucleate boiling regime. The contribution to the energy release rate from the metal-water reaction was not included in the mass-energy analysis. However, it is noted that the metal-water reaction energy addition is included in the containment pressure-temperature analysis performed using the COPATTA code.

The reflood and post-reflood phases of the LOCA are simulated using the FLOOD3 computer code. The FLOOD3 code is an extension of the NRC approved FLOODMOD2 code referenced in the SRP (Reference 7.2-3). The use of the FLOOD3 code to calculate mass and energy releases from postulated RCS pipe ruptures is discussed in UFSAR Section 6.2.1.3.4 (Reference 7.2-1).

Similar to the modeling during blowdown, the decay heat model used in FLOOD3 was the ANS 5 - 1971 (+20 percent) decay heat standard.

During the reflood and post-reflood phases, liquid entrainment in the exiting steam flow is calculated based on a Carryout Rate Fraction (CRF), which is defined as the ratio of the mass flow rate out of the core to the mass flow rate into the core. The CRF varies as coolant accumulates in the core. Specifically, the CRF is 0.05 until the core level reaches 1.5 ft. above the bottom of the active core. As the core level increase from 1.5 ft. to 2 ft., the CRF increases linearly from 0.05 to 0.80. The CRF is then held constant (0.80) until the core level increases to an elevation corresponding to 2.0 ft. below the top of the active core. The methodology models a CRF value of 1.0 after the core level increases above the elevation corresponding to 2 ft. below the top of the active core. The modeling of a CRF value of 1.0 after the core level increases above the elevation corresponding to 2 ft. below the top of the active core described above is a conservative deviation from methodology described in the SRP (Section 6.2.1.3 of Reference 7.2-3), which states that a CRF of 0.05 may be used. UFSAR Section 6.2.1.3.4 notes that liquid entrainment in the exiting steam flow is calculated based on a conservative representation of the CRF specified in the SRP.

Although test data indicate that significant condensation of steam occurs at the safety injection location, the model accounts for only 50 percent condensation during the interval when the annulus is predicted to be full and the SITs are injecting. No credit is taken for condensation at the safety injection location at other times.

During the post-reflood phase, the energy in the RCS and SGs is transferred to containment via the exiting break flow. Post-reflood ends when the steam generator secondary temperature has essentially reached equilibrium with the primary side temperature so that there is no longer a significant driving potential for secondary to primary heat transfer. At this time, the RCS and SG inventory and heat structures have cooled to the point that the generation of steam is dominated by fission product decay heat.

Reflood and Post-Reflood Phases for Hot-Leg Breaks

For the hot-leg break, the mass and energy analysis ends at the end of the blowdown phase. Since there is no viable means for the exiting break flow to pass through the SGs prior to exiting the RCS to containment for a hot-leg break, the reflood and post-reflood phases are not simulated.

Long-Term Cooldown Phase

The LOCA mass and energy analysis for the long-term phase was performed using methods that were consistent with the methodology described in UFSAR Section 6.2 (Reference 7.2-1). UFSAR Section 6.2.1.3.5 states that the LOCA long-term phase M-E analysis is analyzed with use of the COPATTA and CONTRANS codes. This UFSAR section also specifically describes some aspects of the decay heat model.

The long-term cooldown phase of the LOCA completes the transient simulation of this event. In this phase, the analysis accounts for all residual energy in the primary and secondary systems and decay heat. This analysis is typically run until the containment temperature returns to a value near the initial value. The containment response calculation is performed using the COPATTA containment code.

The long-term cooldown phase of the LOCA is simulated using the CONTRANS computer code (Reference 7.2-6). The use of the CONTRANS code to calculate the residual heat addition from primary and secondary metal and the SG inventory is discussed in UFSAR Section 6.2.1.3.5 (Reference 7.2-1). The resulting time dependent energy addition was used as an input to the COPATTA code and added to the reactor vessel or directly to the containment atmosphere. In this manner, all sources of energy were explicitly modeled as follows:

- Commencing with the end of blowdown for hot leg breaks, the residual energy associated with the RCS loop was added to the RCS for use in the COPATTA boil-off model.

- Commencing with the end of the post-reflood phase for cold-leg breaks, the residual energy associated with the RCS loop was added to the RCS for use in the COPATTA boil-off model, and the SG sensible heat was added directly to the containment atmosphere.

Consistent with UFSAR Section 6.2.1.3.5 (Reference 7.2-1), the decay heat input to COPATTA during the long-term cooling phase was based on Branch Technical Position (BTP) ASB 9-2. Prior to the end of blowdown, the decay heat power is included in the mass-energy data.

4.2.3.2.2 LOCA Containment Response Analysis Overview

The LOCA containment response analysis was performed using methods that are consistent with the methodology described in UFSAR Section 6.2 (Reference 7.2-1). UFSAR Section 6.2.1.1.3.1.C states that the containment pressure analyses are performed using the COPATTA computer program. This UFSAR section also specifically describes some aspects of the COPATTA code modeling.

The mass and energy release data was used by the COPATTA computer code (Reference 7.2-7) to calculate the containment pressure and temperature response.

Table 4.2-1 provides the general assumptions and initial conditions for the containment mass and energy release and the containment pressure and temperature response analyses. An overview of the containment response analysis methodology is provided in the following paragraphs.

COPATTA models the containment as three regions – one region models the containment atmosphere (vapor region), another region models the containment sump (liquid region), and the third region models the water contained in the reactor vessel. Conditions in the atmosphere and the sump are determined by solving the conservation of mass and energy equations for each region.

The various structures in the containment are modeled to interact with the containment atmosphere and the sump. Mass and energy are transferred between the liquid and vapor regions by boiling, condensation, or liquid dropout. Evaporation is not considered. A convective heat transfer coefficient can be specified between the sump liquid and atmosphere vapor regions. However, since any heat transfer in this mode is small, a conservative coefficient of zero is assumed. Each region is assumed homogeneous, but a temperature difference can exist between regions. Any moisture condensed in the vapor region during a time increment is assumed to fall immediately into the liquid region. Noncondensible gases are included in the vapor region.

The rate of heat transfer between the containment heat structures and the containment regions is determined by the surface area, the surface temperature, the heat transfer coefficient, the physical arrangement of the conducting masses and the thermal properties of these masses. The heat transfer coefficient used during the turbulent blowdown phase of the event is determined using a modified Tagami correlation (Reference 7.2-7). After the blowdown phase, the heat transfer coefficient transitions from the modified Tagami correlation to the Uchida correlation (Reference 7.2-7).

The containment emergency air cooling units, which are cooled by component cooling water (CCW), remove energy from the vapor region of the containment. COPATTA determines the heat removal due to air cooler unit operation as a function of the time dependent containment saturation temperature and the maximum design component cooling water temperature. The component cooling water system maximum fluid temperature of 105°F is used as input to the COPATTA code. The ECU heat removal rate is based on 1700 gpm to each ECU, rather than the Technical Specification value of 2000 gpm in order to conservatively allow for spent fuel pool cooling (supplied by non-critical loop CCW) concurrent with shutdown cooling utilization (which is supplied by critical loop CCW) during RAS operation.

The containment spray system removes energy from the atmosphere by injecting water into the containment atmosphere. The energy removed from the atmosphere is a function of the heatup of the spray droplets. COPATTA determines the heatup of the droplets from a spray efficiency relationship, which is a function of the ratio of steam mass to air mass. Per COPATTA Topical Report BN-TOP-3 (Reference 7.2-7), this relationship was developed in Reference 7.2-8 assuming a mean spray droplet diameter and fall distance of about 1,000 microns and 20 ft. respectively (actual fall distance averages approximately 100 ft.). The heat removed from the atmosphere due to heating of the spray droplets and any condensate due to this cooling are added to the water in the sump.

COPATTA uses the input from CONTRANS for the reactor vessel region to include the effects of heat transfer from the energy stored in the primary and secondary metal. This region is used only during the long-term cooldown phase, not during the initial mass and energy release phases (blowdown, reflood, and post-reflood) when the primary coolant system pressure is not in equilibrium with the containment atmosphere.

4.2.3.3 Results of LOCA Containment Analysis

Three break locations were investigated: the reactor coolant pump (RCP) discharge and suction legs (i.e., RCS cold legs) and the RCS hot leg. Consistent with UFSAR Section 6.2.1.1 (Reference 7.2-1), all breaks analyzed were double-ended slot breaks.

Consistent with UFSAR Section 6.2.1.1.1.1 (Reference 7.2-1), off-site power was assumed to be lost at the initiation of the LOCA. This provided the maximum delay in the starting of the containment heat removal systems.

Two types of single active failures were considered. The first represented the failure of a diesel generator (DG) to start, resulting in the failure of one train of containment spray and one train of emergency air cooling units. This first failure is characterized by one train of (i.e., minimum) safety injection flow. The second represented the failure of either one train of containment spray or the failure of one train of emergency air cooling units. This second failure is characterized by two trains of (i.e., maximum) safety injection flow. Experience with previous analyses has shown that the limiting single active failure is encompassed by these failures. The COPATTA analysis showed that the failure of one DG was limiting.

4.2.3.3.1 Results for Limiting LOCA Event

Table 4.2-2 lists the maximum containment pressure and temperature results for all LOCA cases analyzed. As shown, the resulting maximum pressure was 48.0 psig, for a double-ended slot break in the hot leg with an assumed failure of one DG. This maximum pressure is less than the containment design pressure of 60 psig.

The transient pressure and temperature for the maximum pressure case are shown in Figure 4.2-1. As shown, the containment pressure and temperature peak at a maximum of 48.0 psig and 273°F at 16 seconds, which is before the containment sprays began operation.

The pressure profiles at 24 hours (86,400 seconds) post-LOCA show that the pressure is below half of the peak pressure thereby confirming compliance with GDC 38.

The limiting containment liner temperature case is the double-ended reactor coolant pump discharge leg break with diesel generator failure. The maximum liner temperature was calculated to be 251°F, which is considerably less than the containment design temperature of 300°F. For LOCA, the peak liner temperature occurs at 350 seconds.

For LOCA, the containment ECU inlet temperature remains below its design temperature of 300°F during the entire event.

The following table compares the limiting case to the previous analysis results as presented in UFSAR Tables 6.2-9 and 6.2-16 (Reference 7.2-1), and the acceptance limits.

Criterion	Analysis with OSG	Analysis with RSG	Acceptance Limit
Peak Pressure ≤ Design Pressure	45.9 psig*	48.0 psig**	≤ 60 psig
Peak Liner Temperature ≤ Design Temperature	250°F*	251°F*	≤ 300°F

Notes:

* Double ended discharge leg slot (DEDLS) break with a loss of offsite power and an assumed failure of a diesel generator.

** Double ended hot leg slot (DEHLS) break with a loss of offsite power and an assumed failure of a diesel generator.

Although the RSG LOCA limiting pressure is higher than the previous OSG LOCA analysis results, the RSG LOCA limiting pressure remains less than the previous OSG MSLB analysis results of 56.5 psig, and the RSG LOCA limiting pressure continues to meet the acceptance criterion.

Although the RSG LOCA containment liner temperature is 1°F higher than the previous OSG LOCA analysis results, the RSG LOCA containment liner temperature continues to meet the acceptance criterion.

The reason for the higher LOCA limiting pressure and the higher containment liner temperature is the increased primary and secondary inventory in the RSG.

4.2.4 MSLB Containment Analysis

The MSLB containment event is characterized by the rapid blowdown of steam into the containment due to a rupture in a main steam line. The location of this break is at one of the SG outlet nozzles. The limiting break size is the largest break area that results in an all steam blowdown. The analysis begins with a double-ended guillotine break. If there is liquid in the break discharge, slot breaks are modeled and the break size is reduced until an all steam blowdown is achieved.

A steam nozzle flow-limiting device is installed in the RSG outlet nozzle. The device consists of seven 8-inch ID venturi nozzles installed in the holes in the steam outlet nozzle integral to the upper head. The venturis are secured in the steam outlet nozzle by welds. The OSG does not have a steam flow restrictor integral to the steam nozzle. Due to the steam flow restrictor devices installed in the RSG outlet nozzle, a 7.406 ft^2 double-ended guillotine break of the steam line as seen by the RSGs is limited to 2.8 ft^2. This results in an all steam blowdown from the RSGs even when a 7.406 ft^2 double-ended guillotine break of the steam line is modeled. For this reason, all the main steam line break sizes are modeled as 7.406 ft^2 double-ended guillotine breaks. The analytical response of the plant protection systems to pipe breaks is discussed in Section 4.2.1. The following discussion augments that discussion as it applies to MSLB events.

Until the main steam isolation valves (MSIVs) close, the initial portion of the transient is characterized by the blowdown of both SGs, including the main steam lines downstream of the MSIVs. In this early phase of the event, steam continues to flow to the turbine. Following the reactor trip, the turbine stop valves close. During this portion of the transient, main feedwater flow to the affected SG is held constant at the transient peak feedwater flow rate until the feedwater is isolated. Cases initiated from 0-percent power assume that the AFW system is in service.

When the containment pressure exceeds the containment high pressure setpoint (5.0 psig analysis value, plus a time delay for actuation signal processing), a SIAS, CIAS, CCAS and reactor trip occur. The SIAS initiates a 10 second (± 2.5 second) sequencer to start the containment spray pumps. The CIAS will close the MSIVs, MFIVs, and main-feedwater block valves, which function as back-up isolation for the MFIVs. The CCAS actuates the containment emergency air cooling units. The containment high-high pressure setpoint will initiate the CSAS, which will cause the containment spray isolation valves to stroke open.

Following the closure of the MSIVs, the flow of steam to the containment from the intact SG and isolated steam line cease. The mass and energy release to the containment continues until the affected SG is blown down.

Although AFW is actuated on an emergency feedwater actuation signal (EFAS), the SG delta-pressure comparison within the EFAS logic is credited to prevent the flow of AFW to the affected SG. As a result, the affected SG essentially boils dry, thus ending the mass and energy release to the containment.

The MFIV failure cases account for the difference in feed line volume when the main-feedwater block valves, rather than the MFIVs, are assumed to provide the isolation of main feedwater to the steam generators. The MSIV failure cases account for the volume of the main steam line header down-stream of the MSIV to the turbine stop valves. The mass and energy release cases without either a MFIV or MSIV failure do not need to consider mass beyond the MSIV and MFIV post CIAS, since the single active failure is the containment cooling train failure. The effect on containment pressure-temperature due to reduced cooling associated with a failure of a containment cooling train, an MFIV failure, or an MSIV failure are all analyzed with the COPATTA containment code for several power plateaus.

4.2.4.1 Impact of RSG Changes on MSLB Containment Analysis

The following RSG changes impact the MSLB containment analysis:

1. The change in internal design produces inventory differences over the power range. This affects the mass available to be transferred to the containment from the affected steam generator.

2. The SG tube heat transfer area and height have changed. This affects the heat transfer rate between the RCS and the SGs.

3. The steam flow restrictor devices installed in the RSG outlet nozzles limit the rate of SG mass and energy blowdown, which reduces the rate at which SG pressure decreases during the blowdown. This results in a longer blowdown period. This also affects the main steam isolation signal (MSIS) timing, which (in addition to closing the MSIV) closes the MSIV bypass valves which are typically only open when heating up the secondary system (e.g., the zero power MSLB cases).

4. The timing to reach containment pressure setpoints leading to the closure of the MSIVs, MFIVs and main-feedwater block valves is longer due to the reduced steam flow through the steam flow restrictor devices installed in the RSG outlet nozzles. A delay in closing the MSIVs and MFIVs affects the mass added to the containment from the affected SG and the intact SG.

4.2.4.2 Methodology Used for MSLB Evaluation

Similar to the LOCA, the MSLB containment analysis was performed in two parts. The SGNIII computer code was used to determine the mass and energy discharged from each SG into the containment. This mass and energy data was then used to determine the containment response using the COPATTA computer code. This subsection describes the impact of the changes on the MSLB analysis and provides an overview of the mass and energy analysis and the analysis results. The description of the containment response analysis is very similar to that discussed in Section 4.2.3. Therefore, only the differences in the containment response analysis assumptions are described in this subsection. Table 4.2-3 provides an overview of the significant assumptions for the mass and energy calculations and the MSLB containment response calculation.

4.2.4.2.1 MSLB Mass and Energy Analysis Overview

The MSLB mass and energy analysis was performed using methodology that is consistent with Section 6.2.1.4 of the UFSAR (Reference 7.2-1). UFSAR Section 6.2.1.4 states that the MSLB mass and energy data is analyzed with use of the SGNIII code. UFSAR Section 6.2.1.4.4 specifically describes some aspects of the SGNIII code modeling.

The SGNIII MSLB methodology (Reference 7.2-9) was used to determine the mass and energy release data. SGNIII is a coupled primary and secondary model that calculates a time dependent mass and energy release. The mathematical model used in SGNIII divides the RCS into a reactor core region, and for each loop, an inlet plenum and pipe, SG tubes, and an outlet plenum and pipe regions. The secondary side of each SG consists of a steam and water volume. The core model is represented by one-group point kinetics with six delayed neutron groups. After reactor trip, decay heat generation is modeled using the approved decay heat model (a conservative representation of the 1971 ANS decay heat standard with a multiplier of 1.2). The SGNIII design inputs were chosen to produce a conservative estimate of the mass and energy release. The Moody critical flow correlation was used to determine break flow rate.

Results from an existing simple hydraulic pressure balance feedwater model (Reference 7.2-10) developed for the OSGs calculated the contribution of main feedwater, including flashing, to the affected and intact SGs. This model accounted for the condensate pumps, heater drain pumps and feedwater pumps characteristics. The model also accounts for piping resistance, high pressure feedwater heaters, main feed regulating valves and check valves. These parameters remain applicable with the RSGs.

The OSG full-power feedwater flow rate is slightly higher than the full-power feedwater flow rate with the RSGs. Therefore, the use of OSG-based data for feedwater flow rate code input data will tend to slightly over-predict the RSG feedwater flow rate thus providing some conservatism. Additional conservatism is provided by stepping the feedwater flow to peak flow and maintaining peak flow until the feedwater isolation valve closes. Increasing resistance in the feedwater line, such as the introduction of condensate polishers, which occurred since Reference 7.2-10 was developed, will tend to reduce flow, further increasing the conservatism of the feedwater code results. The steam flow restrictor devices installed in the RSG outlet nozzles tend to hold the steam generator pressures a bit higher. This too reduces feedwater flow. Reference 7.2-10 continues to provide conservative peak feedwater flow values for this analysis.

While the mass and energy release analysis was conducted separately from the containment response analysis, the SGNIII code can run coupled to the CONTRANS containment code. Coupling SGNIII and CONTRANS will establish the times for the containment pressure to reach the SIAS and CSAS setpoints. The CONTRANS code was coupled with the SGNIII code such that a time-dependent containment pressure and temperature response was calculated simultaneously with the mass and energy release. In order to produce similar actuation times, the CONTRANS containment model utilized identical heat sinks and initial conditions as the COPATTA code.

4.2.4.2.2 MSLB Containment Response Analysis Overview

The MSLB containment response analysis was performed using methods that are consistent with the methodology described in UFSAR Section 6.2 (Reference 7.2-1). UFSAR Section 6.2.1.1.3.1.C states that the containment pressure analyses are performed using the COPATTA computer program. This UFSAR section also specifically describes some aspects of the COPATTA code modeling.

The containment pressure and temperature response to a MSLB is calculated using the COPATTA computer program. The program model description and thermodynamic assumptions are provided in Section 4.2.3.2.2. The primary differences between the LOCA analysis and the MSLB analysis are:

- The reactor vessel region model is not employed in the MSLB analysis.
- The Uchida correlation is used for the heat transfer coefficient to the structural heat sinks in the MSLB, rather than the Modified Tagami correlation.

4.2.4.3 Results of MSLB Evaluation

A single break size was analyzed (7.406 ft^2 guillotine downstream of the steam flow restrictor devices installed in the RSG outlet nozzles, which each have a flow area of 2.8 ft^2). Due to the steam flow restrictor device installed in the RSG outlet nozzle, a double-ended guillotine break at all initial power levels produced no entrainment in the break flow. Since the limiting break size is the largest break for which there is no entrainment in the break flow, there was no need to evaluate smaller break sizes.

Off-site power was assumed to be available throughout the transient. Although the loss of off-site power delays the actuation of containment heat removal systems, the influence of running Reactor Coolant Pumps (RCPs) on transferring RCS energy to the affected steam generator is a more dominant effect.

There are several trade-offs in determining the limiting initial conditions with regard to the power level versus inventory and feedwater flow inputs. As initial power level increases, RCS temperature and core decay heat increase and more primary to secondary energy is present to boil-off the SG inventory. Main feedwater flowrate and enthalpy increase accordingly. However, initial SG inventory decreases with increasing initial core power. Therefore, the MSLB analysis for peak containment pressure includes an evaluation of multiple power levels. The mass and energy sensitivity study included five power levels (100.58-, 80-, 50-, 20- and 0-percent power). Note that the RSG analysis is based on the currently authorized full power rating of 3438 MWth. Subsequent to the prior analysis, the NRC granted SONGS Units 2 and 3 Facility Operating License Amendments 180 and 171, respectively, to change the licensed power limit and an exception from the 10 CFR Part 50 Appendix K requirement to use a 2-percent power measurement uncertainty in ECCS/LOCA related analyses (Reference 7.2-11). The sum of the licensed power limit and the power measurement uncertainty did not change as a result of the NRC action. Consequently the analysis power (licensed power plus power measurement uncertainty) for the decay heat model, as well as the full-power mass-energy and pressure-temperature cases, did not change even though the NRC granted a change in the licensed full power level.

Since several power levels were evaluated in this analysis, a number of power dependent inputs were adjusted to conservatively reflect plant conditions for each power level. The code inputs and trip logic associated with isolating the intact SG and the main feedwater flow were selected such that a conservative response would result.

The failure of an MSIV to close, failure of a MFIV to close and the failure of a containment cooling train to activate, were evaluated, for mass and energy release and containment response. The limiting single failure was determined to be the failure of a main steam isolation valve to close for a MSLB event initiated while at 0-percent power.

Table 4.2-4 shows the maximum pressures and temperatures calculated for all cases analyzed. Table 4.2-4 also shows the maximum pressure and temperature calculated for the environment qualification (EQ) assessment. These EQ assessment pressure and temperature values bound the peak conditions for separate EQ cases evaluating the various single failures, as well as the limiting non-EQ case run. The primary differences between the EQ and non-EQ case runs are listed in Table 4.2-3.

4.2.4.3.1 Results for Limiting MSLB Event

As indicated in the preceding paragraphs, the limiting event was for a MSLB initiated while at 0-percent power, with failure of a MSIV to close. The resulting containment pressure and temperature transient responses are shown in Figure 4.2-3. As shown, the resulting maximum containment atmosphere temperature was 380°F, which occurred at 36 seconds when containment spray flow was ramping to full flow. The figure also shows that the peak pressure was 51.5 psig, occurring at 168 seconds.

The MSLB event is analyzed for a minimum of 5000 seconds (1.39 hours) at which time the pressure is well below half of the peak pressure, thereby confirming compliance with GDC 38 for MSLB as well.

Although the containment atmosphere is superheated during a portion of the transient, the initial temperatures of the structures in containment are subcooled. As a result, steam condenses on the surface of the structures. Since condensate forms at the saturation temperature corresponding to the partial pressure, the structures in the containment are subjected to a temperature that is less than the temperature of the atmosphere. Figure 4.2-2, shows that the maximum MSLB containment liner temperature was calculated to be 251°F at 250 seconds, which is well below the design temperature of 300°F.

For MSLB, the containment atmosphere and ECU inlet temperature peak is above 300°F, but this peak is lower than the peak with the OSG. For SONGS, the MSLB event exceeding 300°F for a short duration has been previously reviewed and approved by the NRC in the NUREG-0712 SER (Reference 7.2-4). Per UFSAR Section 6.2.2.1.3, although the containment atmosphere may exceed 300°F, it does not necessarily mean that environmental qualification test temperatures are exceeded.

The following table compares the limiting case to the previous analysis results as presented in UFSAR Tables 6.2-9 and 6.2-16D (Reference 7.2-1), and the acceptance limits.

Criterion	Analysis with OSG	Analysis with RSG	Acceptance Limit
Peak Pressure ≤ Design Pressure	56.5 psig	51.5 psig	≤ 60 psig
Peak Liner Temperature ≤ Design Temperature	233°F	251°F	≤ 300°F

The RSG MSLB limiting pressure is lower than the previous OSG MSLB analysis results, and as such, the RSG MSLB limiting pressure continues to meet the acceptance criterion. The reason for the lower MSLB limiting pressure is that the RSG design incorporates a steam flow restrictor device in the RSG outlet nozzle.

Although the RSG MSLB containment liner temperature is 18°F higher than the previous OSG MSLB analysis results, the RSG MSLB containment liner temperature continues to meet the acceptance criterion. The reason for the higher MSLB containment liner temperature is the increased primary and secondary inventory in the RSG.

Table 4.2-1 Summary of Significant Inputs for LOCA Containment Response Calculations	
Sources of Energy	Reactor power prior to trip and decay heat Stored metal energy in the core and primary system, including the core and reactor vessel internals Primary system liquid and pressurizer steam inventory Steam generator steam and liquid inventory Steam generator metal energy, including U-tubes Main feedwater prior to feedwater pump trip and the inventory in the feedwater lines downstream of the feedwater isolation valves after feedwater pump trip
Sources of Mass	Primary system inventory Water from safety injection tanks Water added from the refueling water storage tank (RWST) via the safety injection and containment spray pumps
Mass and Energy Release – Significant Points of Methodology	
CEFLASH-4A	A double-ended slot break was postulated for all breaks analyzed. Previous analyses have shown that this break size and configuration are limiting Loss of offsite power was postulated at the initiation of the loss-of-coolant accident (LOCA). This delays the actuation of the containment heat removal systems. Although one case simulated the failure of 1 diesel generator (i.e., takes credit for 1 train of safety injection pumps) and another case simulated the failure of 1 containment heat removal system (i.e., takes credit for 2 trains of safety injection pumps), the CEFLASH-4A analyses take no credit for safety injection pump flow. The reactor was shutdown on voids. The core heat transfer stays in nucleate boiling, via the Jens Lottes correlation, except when single phase steam is predicted. The core heat transfer is allowed to return to nucleate boiling as conditions permit throughout the transient. This maximizes the heat transfer from the fuel to the water. The mass discharge into the containment was modeled via the Henry-Fauske/Moody critical flow models. Steam flow was conservatively isolated at the initiation of the event to maximize the energy in the SGs. RCS volume was conservatively calculated based on expansion of the reactor loop from cold to hot operating conditions. Maximum pressurizer pressure and 68.2% SG water level were used. A minimum Technical Specification RCS flow-rate was assumed to maximize the initial RCS temperature distribution. The initial cold leg temperature was maximized to increase the energy release to containment. Consistent with the postulated loss-of-offsite power, the reactor coolant pumps were tripped at the initiation of the LOCA. Decay heat was based on the ANS 1971 decay heat standard with a power multiplication factor of 1.2. Initial SIT liquid volume was nominal. Initial SIT pressure was at the maximum Technical Specification pressure value. Initial SIT temperature was at the maximum based upon the assumed conditions in the containment.

Table 4.2-1 Summary of Significant Inputs for LOCA Containment Response Calculations	
FLOOD3	The refill period was conservatively omitted. One train and two train SI pump scenarios were evaluated for the cold leg breaks. Similar to the blowdown phase, decay heat during reflood and post-reflood phases of the event was based the ANS 1971 decay heat standard with a power multiplication factor of 1.2. Consistent with the blowdown analysis, nominal loop resistances were assumed. Credit was taken for 50% condensation of break flow during the time interval that the annulus is filled and the SITs are discharging water. No credit for condensation due to SI pump flow was assumed.
CONTRANS	Consistent with the reflood methodology for the cold leg breaks, all primary and secondary system metal, and SG secondary inventory, was included in the calculation. The pre and post-RAS safety injection flowrates were consistent with the long-term cooldown methodology.
Containment Response Calculation Assumptions	
Free Volume/ Surface Area	Minimum free volume, and exposed heat structure surface areas, were assumed.
Metal Water Reaction	Since the methodology conservatively maximizes heat removal from the core, very little clad heatup is predicted. As a result, the chemical reaction between the cladding and the water does not occur. Therefore, the heat input from metal-water reaction was not included in the mass-energy data but was included in the COPATTA containment analysis.
Initial Conditions	Initial pressure and temperature were assumed to be at their maximum values. The initial relative humidity was assumed to be at a minimum value.
ESF Actuation	The setpoints for actuating Containment Cooling (CCAS) and Containment Spray (CSAS) used the safety analysis limits.
Heat Transfer from Sump	Except for times when the water in the containment emergency sump was boiling, heat transfer between the sump and atmosphere was conservatively neglected.
Component Cooling Water	The air coolers and shutdown cooling heat exchanger and their component cooling water (CCW) flow were explicitly modeled in the COPATTA analysis. The CCW maximum temperature was modeled.
Long-Term Cooling	The mass and energy balance for the reactor vessel was explicitly calculated by COPATTA. Sensible heat was added to the fluid in the reactor vessel or directly to the containment atmosphere, as appropriate, to model RCS loop stored energy, secondary side stored energy, upper head and miscellaneous reactor vessel and pressurizer stored energy. Decay heat was based on ASB 9-2. Prior to the end of blowdown, the decay heat power is included in the mass-energy data.

Table 4.2-2 Maximum Post-LOCA Containment Pressures and Temperatures				
	Pressure		**Temperature**	
Description	**P (psig)**	**Time (sec)**	**T (°F)**	**Time (sec)**
Double-Ended Discharge Leg Slot (DEDLS), Failure of 1 Diesel Generator (DG)	46.7	263	267	263
DEDLS, Failure of 1 Containment Spray (CS) Train	46.4	203	267	197
DEDLS, Failure of 1 Emergency Air Cooling Unit (ECU) Train	46.0	196	266	196
Double-Ended Suction Leg Slot (DESLS), Failure of 1 DG	42.0	18	263	41
DESLS, Failure of 1 CS Train	42.0	18	263	41
DESLS, Failure of 1 ECU Train	42.0	18	263	37
Double-Ended Hot Leg Slot (DEHLS), Failure of 1 DG	48.0	16	273	16
DEHLS, Failure of 1 CS Train	47.9	16	273	16
DEHLS, Failure of 1 ECU Train	47.9	16	273	16

Table 4.2-3 Significant Points of MSLB Event Analysis Methodology	
#	Points
1	The MSLB calculation uses the maximum RCS flow rate. This is conservative because it allows the maximum possible heat transfer to occur between the primary and secondary.
2	A conservative and realistic expansion factor of 2% is used to accommodate expansion due to pressure and temperature, in calculating the RCS/SG liquid and steam volume inputs to the SGNIII computer code.
3	Uncertainties are not considered in the initial SG normal water level. The steam separation rate multiplier of 2.5 preserves conservative mass and energy data without summing up water level uncertainties.
4	No safety injection flow is assumed. Addition of cold liquid due to safety injection to the RCS would decrease the amount of primary heat used to boil off the ruptured SG inventory. In addition to reducing the heat transferred to the secondary side, the safety injection would delay the transient giving the passive heat sinks time to absorb energy.
5	No tube plugging is assumed when generating mass and energy for steam line breaks. Less active tube area reduces primary to secondary heat transfer area and thus slows the heat addition to the secondary inventory.
6	Per the NRC's letter IN-84-90, steam superheating upon uncovering of the SG tubes is assumed for all the MSLB Equipment Qualification (EQ) cases.
7	Consistent with current methodology from NUREG-0588, the containment MSLB Equipment Qualification cases take credit for 0.08 re-evaporation of condensate from the heat sinks.
8	The feedwater flow to the affected SG is held constant at the transient peak feedwater flow rate until the feedwater is isolated.
9	The initial feedwater pipe pressure is assumed to equal initial SG pressure.
10	Due to the relative quickness of the events analyzed, there is no attempt to model the post trip effect on the feedwater heaters, and the feedwater enthalpy is assumed to remain constant.
11	This analysis takes credit for the SG High ΔP logic to isolate emergency feedwater from the affected SG. No Auxiliary Feedwater is injected into the affected steam generator.
12	In order to insure that the SGNIII containment computer code time for initiating signals on containment high pressure is comparable to that modeled with COPATTA, 1 psi has been added to the SCE containment high pressure analysis setpoint of 5 psig.
13	Peak pressure MSLB cases use the maximum initial containment pressure value for conservatism.
14	MSLB EQ cases are initialized with the lowest allowable containment pressure. Minimizing the amount of air inside containment reduces the heat capacity of the vapor and maximizes the temperature response of containment to the MSLB event.
15	The mass and energy release to the containment during most of the SG blowdown phase of a MSLB is based on critical flow and independent of the containment pressure. However the containment is modeled to provide the timing for reactor trip and SG isolation.
16	Main feedwater flow is maintained at peak flow until the main feedwater isolation signal delay time and MFIV stroke time have elapsed. The termination of the main feedwater flow in this analysis assumes step closure of the MFIVs. This provides conservative results over ramping closed.

Table 4.2-3 Significant Points of MSLB Event Analysis Methodology	
#	**Points**
17	For all but the best estimate cases, the break sizes are the largest break size break that results in an all steam blowdown. The steam line flow restrictor device in the RSG outlet nozzle provides for an all steam blowdown with the largest pipe break. This method is consistent with generating mass and energy to meet General Design Criterion (GDC) 50.
18	SG level is not used to initiate any action in this analysis.
19	The 0% power cases will initiate with 1 MWt core power and the applicable reactor coolant pump heat.
20	The input deck to SGNIII is biased to maximize the initial RCS sensible heat. The RCS can demonstrate a slight increase in temperature over the first few seconds prior to the cooldown induced by the steam line break. The containment MSLB analyses are run using a neutral MTC to maintain the desired power up to the time of reactor trip.
21	The evaluation of a 20 MW return to power indicates a return to power is not a significant concern in the generation of MSLB mass and energy.
22	The Steam Line Header cross connect area and flow resistance (fL/D) are the same prior to and after the reactor trip. Flow from the unaffected steam generator is not reduced after turbine stop valve closure.
23	The turbine stop valves are conservatively assumed to close immediately (0.01 seconds) after the reactor trip.

Table 4.2-4 Maximum Post-MSLB Containment Pressures and Temperatures					
Initial Power (% 3438 MW)	Single Failure	Pressure		Temperature	
		P (psig)	Time (sec)	T (°F)	Time (sec)
0	MFIV	50.8	181	374	36
20	MFIV	42.4	212	357	35
50	MFIV	44.8	164	364	36
80	MFIV	45.0	141	369	37
100.58	MFIV	45.0	124	371	37
0	MSIV	51.5	168	380	36
20	MSIV	43.1	191	364	35
50	MSIV	44.4	145	370	36
80	MSIV	44.1	119	374	36
100.58	MSIV	43.8	101	376	36
0	Cooling Train	51.0	171	377	40
20	Cooling Train	42.9	196	360	39
50	Cooling Train	43.8	146	368	41
80	Cooling Train	43.7	101	373	42
100.58	Cooling Train	44.5	91	375	43
Bounding EQ	Bounding EQ	51.5	171	380	35

Figure 4.2-1 Limiting LOCA (DEHLS with DG Failure) Containment Pressure and Temperatures

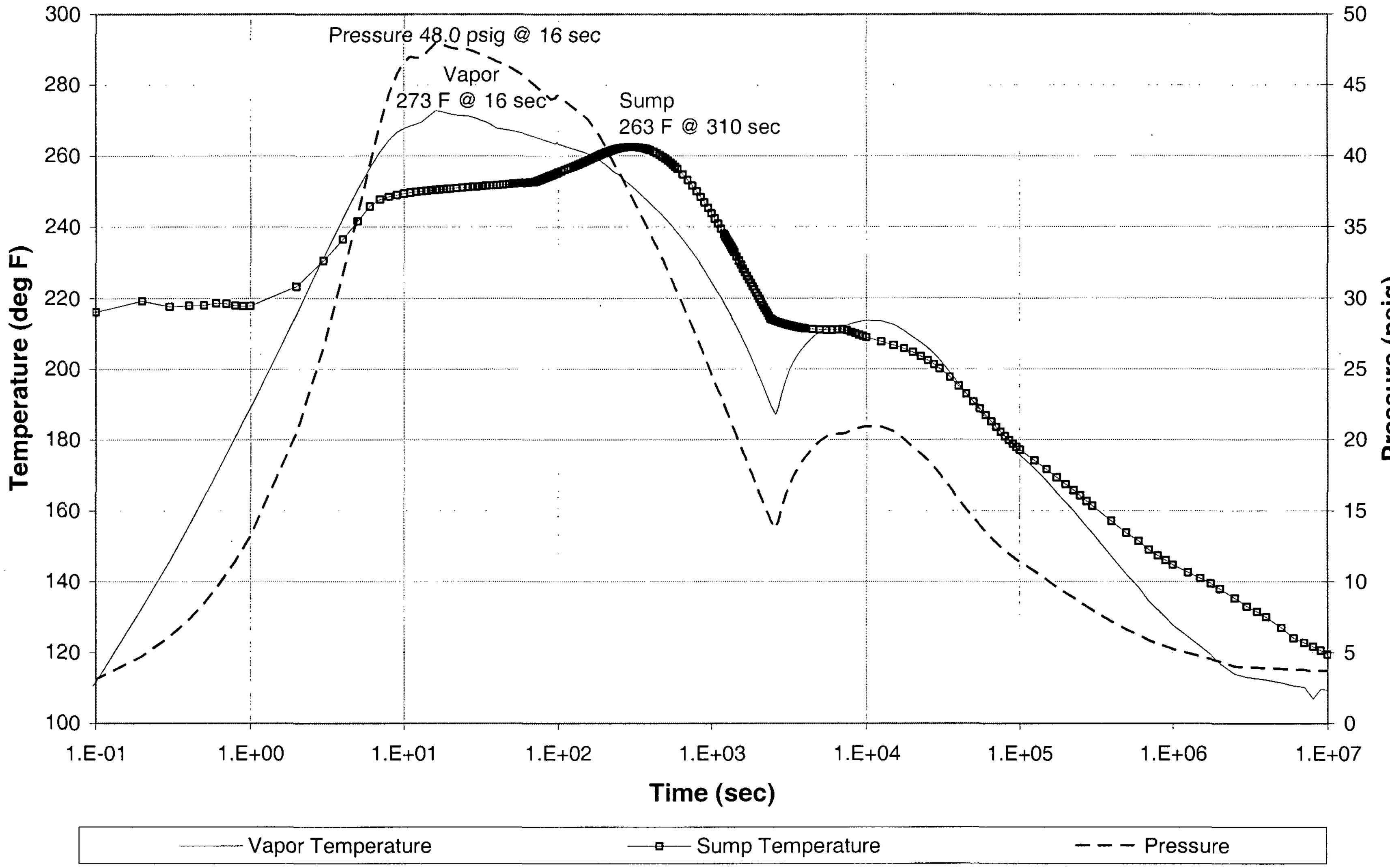


Figure 4.2-2 Limiting LOCA and Non-EQ MSLB Event Containment Liner Temperatures (DEDLS with DG Failure and non-EQ MSLB 0% Power MSIV Failure)

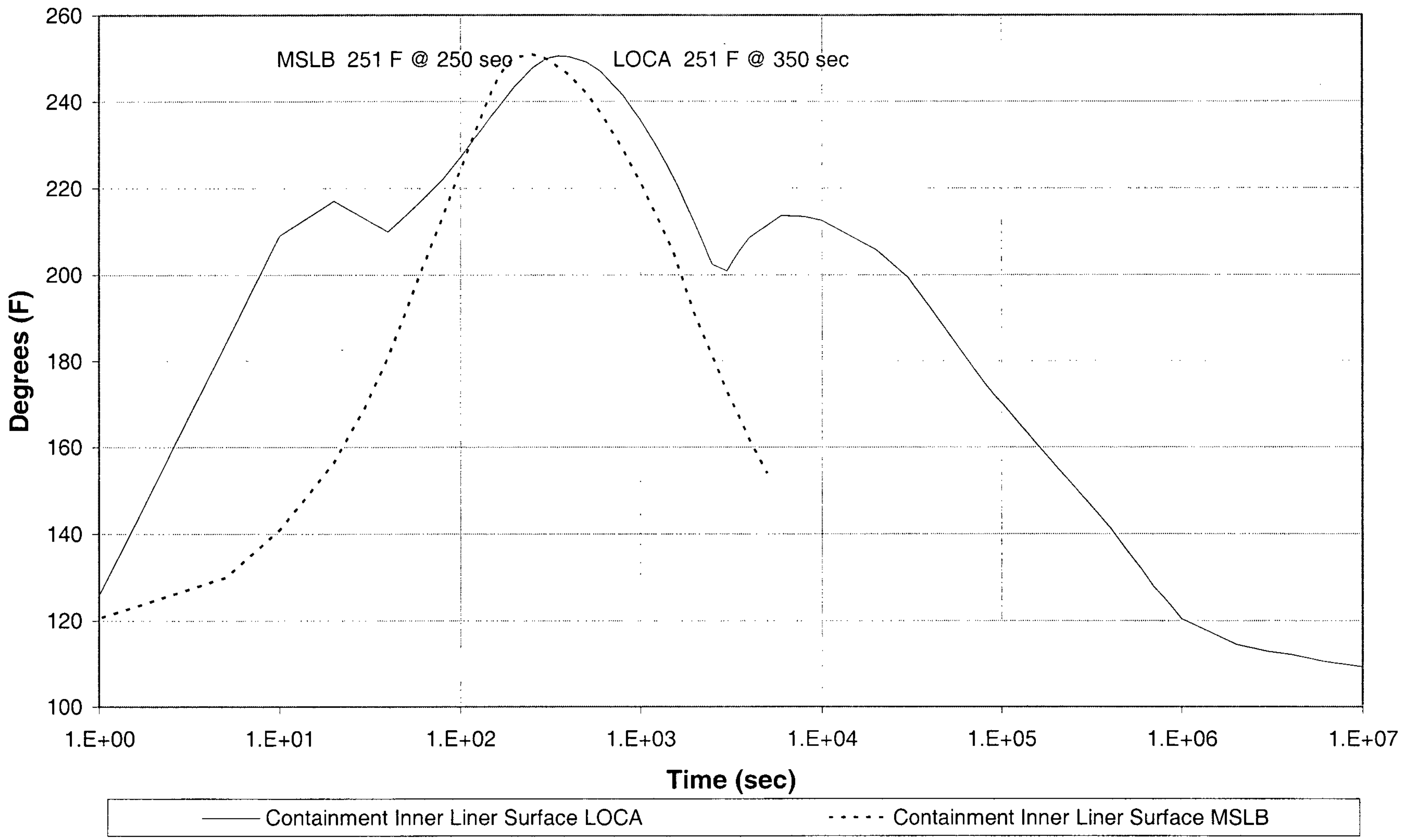
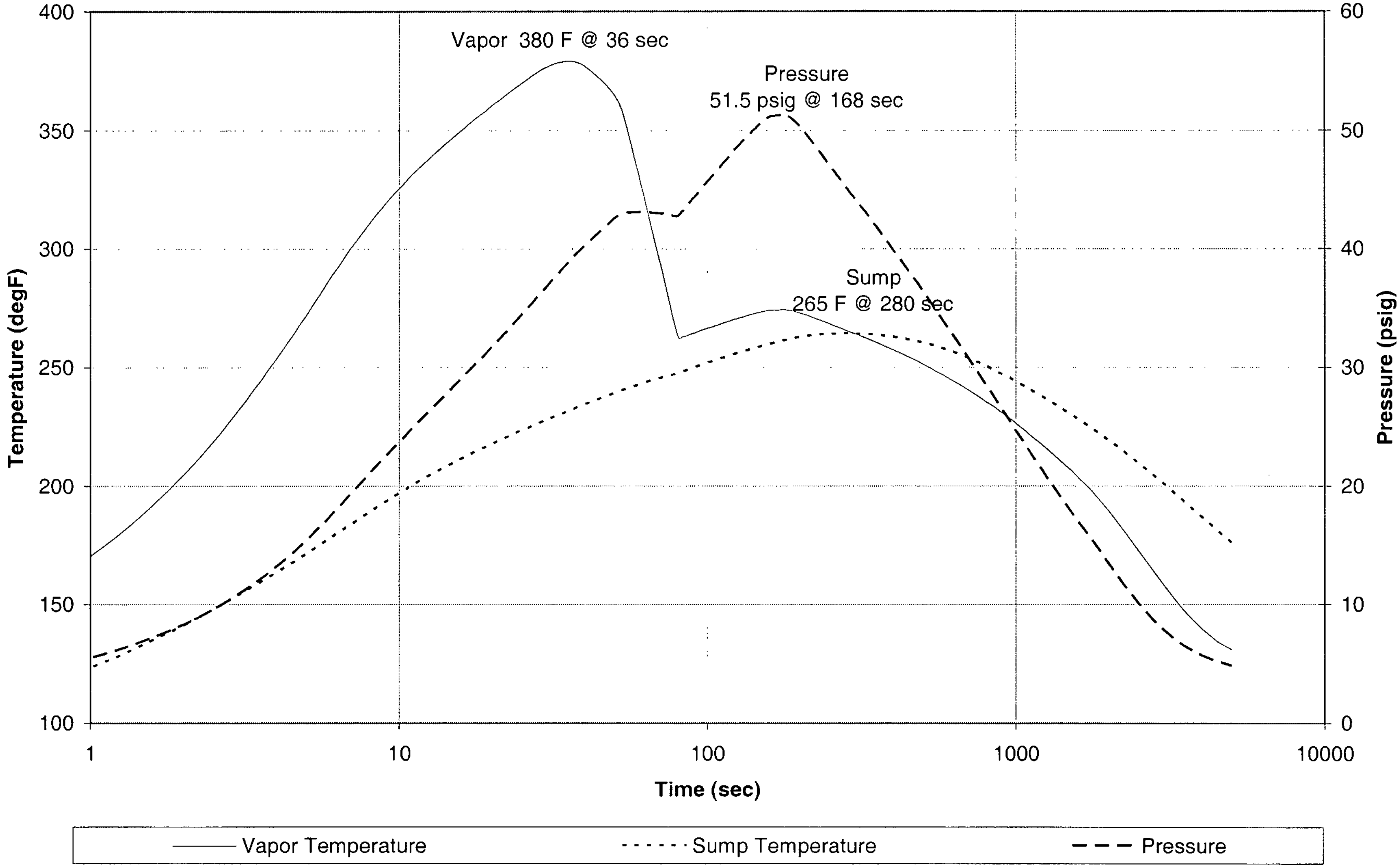


Figure 4.2-3 Limiting MSLB (0% Power with MSIV Failure) Containment Pressure and Temperatures



4.3 LIST OF REGULATORY COMMITMENTS

The proposed steam generator plugging criterion is a preliminary value and SCE will provide a confirmation or corrected value when the calculation is approved.

5.0 REGULATORY SAFETY ANALYSIS

5.1 No Significant Hazards Consideration

Southern California Edison (SCE) has evaluated whether or not a significant hazards consideration is involved with the proposed amendments by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of Amendment", as discussed below:

1. Does the proposed change involve a significant increase in the probability or consequences of an accident previously evaluated?

   Response: No.

   The proposed changes will reflect installation of Replacement Steam Generators (RSGs) at San Onofre Nuclear Generating Station (SONGS) Units 2 and 3. The proposed changes involve revising the Steam Generator (SG) tube inspection and repair criteria and revising the peak containment post-accident pressure.

   The proposed change to revise the SG tube inspection and repair criteria affect Technical Specifications (TSs) 3.4.17, "Steam Generator (SG) Tube Integrity," 5.5.2.11, "Steam Generator (SG) Program," and 5.7.2.c, "Special Reports." The proposed TS 3.4.17, 5.5.2.11, and 5.7.2.c revisions remove the repair method (sleeving), and Alternate Repair Criteria (ARC). The revisions replace the 44% tube repair criterion applicable to the original SGs, with a 35% (preliminary) tube repair criterion applicable to the RSGs. The revisions replace inspection requirements applicable to the tubing material of the original SGs with inspection requirements applicable to the tubing material of the RSGs, thus maintaining consistency with applicable material-specific regulatory guidance (TSTF-449, Revision 4). Overall, these revisions will ensure that all RSG tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 35% (preliminary) of the nominal tube wall thickness will be plugged as required by revised TS 5.5.2.11.c.1.

   The TS 5.5.2.11.b SG structural integrity, accident induced leakage, and operational leakage performance criteria are unchanged and will continue to be met for the RSGs. Meeting the SG performance criteria provides reasonable assurance that the SG tubing will remain capable of maintaining reactor coolant pressure boundary integrity throughout each operating cycle and in the unlikely event of a design basis accident.

The proposed change to the SG tube inspection and repair criteria will not affect the probability of any accident initiators. There will be no degradation in the performance of, or an increase in the number of challenges imposed on, safety-related equipment assumed to function during an accident. There will be no change to accident mitigation performance. The proposed change will not alter any assumptions or change any mitigation actions in the radiological consequence evaluations in the Updated Final Safety Analysis Report (UFSAR).

The proposed change to the peak containment post-accident pressure will revise TS 5.5.2.15, "Containment Leakage Rate Testing Program," by changing the stated values for peak containment internal pressure for the design-basis Loss-of-Coolant Accident (LOCA) and Main Steam Line Break (MSLB) accidents. The current LOCA value of 45.9 psig would be changed to 48.0 psig and the current MSLB value of 56.5 psig would be changed to 51.5 psig.

The proposed change does not affect the probability of occurrence of an accident previously evaluated because it relates solely to the consequences of hypothesized accidents given that the accident has already occurred.

The proposed change increases the calculated peak containment internal pressure for the LOCA events from 45.9 psig to 48.0 psig. The revised post-LOCA peak containment pressure is bounded by the existing and revised post-MSLB peak containment pressure and the containment design pressure of 60 psig. Despite the increase in the post-LOCA peak containment pressure, any post-accident containment leakage will still be limited to less than 0.1% containment air volume per day, consistent with current TS 5.5.2.15. Therefore, there is no increase in the radiological consequences of a LOCA as a result of the change to the post-LOCA peak containment pressure.

The post-MSLB peak containment pressure decreases from 56.5 psig to 51.5 psig. Thus, the peak containment post-accident pressure is decreased as a result of this change, and there is no resulting increase in the consequences of a previously evaluated accident.

Therefore, the proposed changes do not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the proposed change create the possibility of a new or different kind of accident from any accident previously evaluated?

The proposed change to the SG tube inspection and repair criteria deletes the repair method (sleeving) and the ARC applicable to the original SGs, and provides repair criteria and inspection requirements applicable to the RSGs. This will not introduce any adverse changes to the plant design basis or postulated accidents resulting from potential tube degradation. The primary-to-secondary leakage that may be experienced during all plant conditions will be monitored to ensure it remains within current accident analysis assumptions. The proposed change does not adversely affect the method of operation of the SGs or the primary or secondary coolant chemistry controls and does not impact other plant systems or components.

The proposed change to the peak containment post-accident pressure relates to two accidents, LOCA and MSLB, which are already evaluated in the Updated Final Safety Analysis Report (UFSAR).

Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does the proposed change involve a significant reduction in a margin of safety?

Response: No

For the proposed change to the SG inspection and repair criteria, the safety function of the SGs is maintained by ensuring the integrity of the tubes. SG tube integrity is a function of the design, environment, and the physical condition of the SG tubes. The proposed change, which deletes the repair method (sleeving) and the ARC applicable to the original SGs, and provides repair criteria and inspection requirements applicable to the RSGs, does not adversely affect the SG tube design or operating environment. SG tube integrity will continue to be maintained by implementing the TS 5.5.2.11 SG Program to manage SG tube inspection, assessment, and plugging. The requirements established by the TS 5.5.2.11 SG Program are consistent with those in the applicable design codes and standards.

For the change to the peak containment post-accident pressure, the proposed change increases the calculated peak containment internal pressure for the LOCA events from 45.9 psig to 48.0 psig. The revised post-LOCA peak containment pressure is bounded by the existing and revised post-MSLB peak containment pressure. The post-MSLB peak containment pressure decreases from 56.5 psig to 51.5 psig. The proposed peak containment internal pressure for the MSLB accident is less than the containment design pressure of 60 psig and less than the previously calculated pressure.

Therefore, the proposed changes do not involve a significant reduction in a margin of safety.

Based on the above, SCE concludes that the proposed amendments present no significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and accordingly, a finding of no significant hazards consideration is justified.

5.2 Applicable Regulatory Requirements/Criteria

The applicable regulatory requirements and guidance associated with the proposed change to the SG inspection and repair criteria are addressed by the NRC Notice of Availability published May 6, 2005 (70 FR 24126), the NRC Notice for Comment published on March 2, 2005 (70 FR 10298), and TSTF-449, Revision 4. This proposed change will maintain consistency with these regulatory requirements and guidance.

The SONGS Units 2 and 3 UFSAR (Reference 7.2-1) describes adherence to the General Design Criteria (GDC) published as Appendix A to 10 CFR 50 (Reference 7.2-2). GDC 38 and 50 (Containment Heat Removal and Containment Design Basis) are impacted by the proposed RSG changes. In addition, SONGS Units 2 and 3 must meet the requirements of 10 CFR 50.49 regarding the qualification of electrical equipment required to remain functional during and following design basis events. Analyses were performed to demonstrate that the proposed plant configuration with the RSGs meets all applicable criteria. Specifically, the following criteria are used to judge the acceptability of these analyses:

1. The maximum post-accident containment pressure is less than the design pressure of 60 psig (UFSAR Table 6.2-3).

   Following installation of the RSGs, the limiting LOCA containment pressure will be 48.0 psig and the limiting MSLB containment pressure will be 51.5 psig. These results are less than the current limiting post-accident containment pressure of 56.5 psig (associated with an MSLB) and are less than the current design pressure of 60 psig. The change in the limiting MSLB containment pressure represents a decrease in the limiting post-accident containment pressure.

2. The maximum post-accident containment liner temperature is less than the design temperature of 300°F (UFSAR Table 6.2-3). Technical Specification (TS) Bases B3.6.5 clarifies that the temperature limit of 300°F is not a "vapor" temperature limit, but rather pertains to the containment structure such as the containment liner plate and concrete.

   Following installation of the RSGs, the limiting LOCA containment liner temperature will increase from 250°F to 251°F and the limiting MSLB containment liner temperature increases from 233°F to 251°F. These results represent a slight increase from the current limiting post-accident containment liner temperature of 250°F (associated with a LOCA) but are well below the current design temperature of 300°F.

3. The containment heat removal system will reduce the post-accident containment pressure and temperature to a low level following an accident and maintain this low level thereafter. UFSAR Sections 6.2.1.1.1.4, 6.2.2.1.1C and 6.2.2.2.1A, state that the containment emergency fan cooler system, in conjunction with the

Containment Spray System (CSS) and the shutdown heat exchangers (i.e., one train of each system), is capable of reducing the post-LOCA containment pressure from the peak value to one half peak value in 24 hours in accordance with 10 CFR 50 Appendix A GDC 38 (Reference 7.2-2) and Standard Review Plan 6.2.1.1.A (Reference 7.2-3).

The pressure profiles at 24 hours post-LOCA show that the pressure is below half of the peak pressure thereby confirming compliance with GDC 38. The MSLB event is analyzed for 5000 seconds (1.39 hours) at which time the pressure is well below half of the peak pressure, thereby confirming compliance with GDC 38 for MSLB as well.

4. The equipment that must function to mitigate the design basis accidents within the containment is qualified to operate under the resulting environmental conditions. Per UFSAR Section 6.2.2.1.3, the design temperature of equipment subjected to LOCA or MSLB conditions is 300°F. Per UFSAR Table 6.2-34 the emergency cooling unit (ECU) atmosphere inlet temperature is 300°F.

   For LOCA, the containment ECU inlet temperature remains below its design temperature of 300°F during the entire event. For MSLB, the containment atmosphere and ECU inlet temperature peak is above 300°F, but this peak is lower than the peak with the OSG. For SONGS, the MSLB event exceeding 300°F for a short duration has been previously reviewed and approved by the NRC in the NUREG-0712 SER (Reference 7.2-4). Per UFSAR Section 6.2.2.1.3, although the containment atmosphere may exceed 300°F, it does not necessarily mean that environmental qualification test temperatures are exceeded.

In conclusion, based on the considerations discussed above, (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendments will not be inimical to the common defense or security or to the health and safety of the public.

6.0 ENVIRONMENTAL CONSIDERATION

A review has determined that the proposed amendment would change a requirement with respect to installation or use of a facility component, the steam generators, located within the restricted area, as defined in 10 CFR 20 or would change an inspection or surveillance requirement. However, the proposed amendment does not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluent that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed amendments meet the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22 (c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with these proposed amendments.

7.0 REFERENCES

7.1-1 Technical Specification Task Force (TSTF) Standard Technical Specification Change Traveler, TSTF-449, Revision 4, titled Steam Generator Tube Integrity, and associated NRC publications regarding usage (NRC Notice for Comment 70 FR 10298 dated March 2, 2005 and NRC Notice of Availability 70 FR 24126 dated May 6, 2005)

7.2-1 Updated Final Safety Analysis Report (UFSAR) for San Onofre Nuclear Generating Station, Units 2 and 3, Amended May 2007.

7.2-2 10 CFR Part 50 "Domestic Licensing of Production and Utilization Facilities," General Design Criteria for Nuclear Power Plant Construction Permits, Federal Register, Vol. 32, No. 132, July 11, 1967.

7.2-3 U.S. Nuclear Regulatory Commission Standard Review Plan, NUREG-0800, Rev. 2, July 1981.

7.2-4 NUREG-0712, NRC Safety Evaluation Report for SONGS 2 and 3 (including supplements).

7.2-5 CEFLASH-4A, A FORTRAN-IV Digital Computer Program for Reactor Blowdown Analysis, CENPD 133P, August 1974.

CEFLASH-4A, A FORTRAN-IV Digital Computer Program For Reactor Blowdown Analysis (Modifications), CENPD-133P, Supplement 2, February 1975.

CEFLASH-4A, A FORTRAN-IV Digital Computer Program for Reactor Blowdown Analysis, CENPD-133P, Supplement 4-P, April 1977.

CEFLASH-4A, A FORTRAN 77 Digital Computer Program For Reactor Blowdown Analysis, CENPD-133P, Supplement 5, and June 1985.

7.2-6 ABB-CE Topical Report CENPD-140-A, dated June 1976, Description of the CONTRANS Digital Computer Code for Containment Pressure and Temperature Transient Analysis.

7.2-7 Bechtel Power Corporation, "Containment Pressure and Temperature Transient Analysis (COPATTA)," as described in Bechtel topical report BN-TOP-3 Rev. 4 – "Performance and Sizing of Dry Pressure Containments," March 1983.

7.2-8 Tagami, Takashi, "Interim Report on Safety Assessment and Facilities Establishment (SAFE) Project," February 28, 1966, Hitachi Ltd., Tokyo, Japan.

7.2-9 Combustion Engineering letter DP-456, F. M. Stern to E. Case, August 19, 1974, Chapter 6, Appendix 6B to CESSAR System 80 PSAR.

7.2-10 ABB Calculation # S-PEC-189, Revision 0, "Feedwater Flow Model for SONGS II + III," October 18, 1977.

7.2-11 NRC Letter to Mr. Harold B. Ray (SCE), "San Onofre Nuclear Generating Station, Units 2 and 3 - Issuance of Amendments RE: Increase in Reactor Power to 3438 MWt (TAC Nos. MB1623 and MB1624)", July 6, 2001

Attachment A

(Existing Pages)

SONGS Unit 2

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.17 Steam Generator (SG) Tube Integrity

LCO 3.4.17 SG tube integrity shall be maintained.

AND

All SG tubes satisfying the tube repair criteria shall be plugged or repaired in accordance with the Steam Generator Program.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

-----------------------------------NOTE-----------------------------------
Separate Condition entry is allowed for each SG tube.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more SG tubes satisfying the tube repair criteria and not plugged or repaired in accordance with the Steam Generator Program.	A.1 Verify tube integrity of the affected tube(s) is maintained until the next refueling outage or SG tube inspection.	7 days
	AND	
	A.2 Plug or repair the affected tube(s) in accordance with the Steam Generator Program.	Prior to entering MODE 4 following the next refueling outage or SG tube inspection
B. Required Action and associated Completion Time of Condition A not met. OR SG tube integrity not maintained.	B.1 Be in MODE 3.	6 hours
	AND	
	B.2 Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.17.1	Verify SG tube integrity in accordance with the Steam Generator Program.	In accordance with the Steam Generator Program
SR 3.4.17.2	Verify that each inspected SG tube that satisfies the tube repair criteria is plugged or repaired in accordance with the Steam Generator Program.	Prior to entering MODE 4 following a SG tube inspection

5.5 Procedures, Programs, and Manuals (continued)

5.5.2.8 Primary Coolant Sources Outside Containment Program (continued)

system (post-accident sampling return piping only until such time as a modification eliminates the post-accident piping as a potential leakage path). The program shall include the following:

a. Preventive maintenance and periodic visual inspection requirements; and

b. Integrated leak test requirements for each system at refueling cycle intervals or less.

5.5.2.9 Pre-Stressed Concrete Containment Tendon Surveillance Program

This program provides controls for monitoring any tendon degradation in pre-stressed concrete containment, including effectiveness of its corrosion protection medium, to ensure containment structural integrity. Program itself is relocated to the LCS.

5.5.2.10 Inservice Inspection and Testing Program

This program provides controls for inservice inspection of ASME Code Class 1, 2, and 3 components and Code Class CC and MC components including applicable supports. The program provides controls for inservice testing of ASME Code Class 1, 2, and 3 components. The program itself is located in the LCS.

5.5.2.11 Steam Generator (SG) Program

A Steam Generator Program shall be established and implemented to ensure that SG tube integrity is maintained. In addition, the Steam Generator Program shall include the following provisions:

a. Provisions for condition monitoring assessments. Condition monitoring assessment means an evaluation of the "as found" condition of the tubing with respect to the performance criteria for structural integrity and accident induced leakage. The "as found" condition refers to the condition of the tubing during an SG inspection outage, as determined from the inservice inspection results or by other means, prior to the plugging or repair of tubes. Condition monitoring assessments shall be conducted during each outage during which the SG tubes are inspected, plugged, or repaired to confirm that the performance criteria are being met.

5.5.2.11 Steam Generator (SG) Program (continued)

c. Provisions for SG tube repair criteria.

1.Tubes shall be plugged or repaired if the non-sleeved region of a tube is found by inservice inspection to contain flaws with a depth equal to or exceeding 44% of the nominal tube wall thickness, at a location that is not addressed in Technical Specification 5.5.2.11.c.2.

2.Tubes shall be plugged or repaired if the non-sleeved region of a tube is found by inservice inspection to contain flaws at either of the following locations:

a) below the bottom of the hot leg expansion transition or hot leg top of the tubesheet, whichever is higher, or

b) below the bottom of the cold leg expansion transition or cold leg top of the tubesheet, whichever is higher.

3.Tubes shall be plugged if the sleeved region of a tube is found to contain flaws in the:

a) sleeve, or

b) sleeve or original tube wall at a sleeve-to-tube joint.

4.The following C* methodology may be applied in a portion of the expanded tube in the tubesheet region, as an alternative to the repair criteria of Technical Specification 5.5.2.11.c.2. Flaws, in the locations described below, may remain in service regardless of size.

a) For tubes that have not been repaired in the hot leg tubesheet region: Greater than 10.6 inches below the bottom of the hot leg expansion transition or top of the hot leg tubesheet, whichever is lower.

b)For tubes that have not been repaired in the cold leg tubesheet region: Greater than 11.0 inches below the bottom of the cold leg expansion transition or top of the cold leg tubesheet, whichever is lower.

5.5 Procedures, Programs, and Manuals (continued)

5.5.2.11 Steam Generator (SG) Program (continued)

c) For tubes that have been repaired in the hot leg tubesheet region: Below the bottom of the lower sleeve-to-tube joint or greater than 10.6 inches below the bottom of the hot leg expansion transition or greater than 10.6 inches below the top of the hot leg tubesheet, whichever of these three is lowest.

d) For tubes that have been repaired in the cold leg tubesheet region: Below the bottom of the lower sleeve-to-tube joint or greater than 11.0 inches below the bottom of the cold leg expansion transition or greater than 11.0 inches below the top of the cold leg tubesheet, whichever of these three is lowest.

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube repair criteria. The tube-to-tubesheet weld is not part of the tube. In tubes repaired by sleeving, the portion of the original tube wall between the sleeve's joints is not an area requiring re-inspection.

-------------------------NOTE------------------------------

The requirement for methods of inspection with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube does not apply to the portion of the original tube wall adjacent to the nickel band portion (the lower half) of the lower joint for the repair process that is discussed in Technical Specification (TS) 5.5.2.11.f.1. However, the method of inspection in this area should be a rotating plus point (or equivalent) coil. The SG tube repair criterion of TS 5.5.2.11.c.3.b is applicable to flaws in this area.

In addition to meeting the requirements of d.1, d.2, d.3, and d.4 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. An assessment of degradation shall be performed to determine the

5.5 Procedures, Programs, and Manuals (continued)

5.5.2.11 Steam Generator (SG) Program (continued)

type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

1. Inspect 100% of the tubes in each SG during the first refueling outage following SG replacement.

2. Inspect 100% of the tubes at sequential periods of 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the SGs. No SG shall operate for more than 24 effective full power months or one refueling outage (whichever is less) without being inspected.

3. If crack indications are found in any SG tube, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever is less). If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

4. All sleeves shall be inspected with eddy current prior to initial operation. This includes pressure retaining portions of the parent tube in contact with the sleeve, the sleeve-to-tube weld and the pressure retaining portion of the sleeve.

e. Provisions for monitoring operational primary to secondary LEAKAGE.

f. Provisions for SG tube repair methods. Steam generator tube repair methods shall provide the means to re-establish the RCS pressure boundary integrity of SG tubes without removing the tube from service. For the purposes of these Specifications, tube plugging is not a repair. All acceptable tube repair methods are listed below.

1. TIG welded sleeving with heat treatment, as described in ABB/CE Topical Report, CEN-630-P, Rev. 2, is currently approved by the NRC until December 2009. All sleeves shall be removed from service by December 2009.

   Tube repair can be performed on certain tubes that have been previously plugged as a corrective or preventive measure. A tube inspection of the entire length of the tube shall be performed on a previously plugged tube prior to returning the tube to service.

5.5 Procedures, Programs, and Manuals (continued)

5.5.2.15 Containment Leakage Rate Testing Program

A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995 as modified by the following exception:

NEI 94-01 - 1995, Section 9.2.3: The first Type A Test performed after the March 31, 1995 Type A Test shall be performed no later than March 30, 2010.

The calculated peak containment internal pressure related to the design basis loss-of-coolant accident, P_a, is 45.9 psig (P_a will conservatively be assumed to be equal to the calculated peak containment internal pressure for the design basis Main Steam Line Break (56.5 psig) for the purpose of containment testing in accordance with this Technical Specification).

The maximum allowable containment leakage rate, L_a, at P_a, shall be 0.10% of containment air weight per day.

Leakage rate acceptance criteria are:

a. The Containment overall leakage rate acceptance criterion is $\leq 1.0\ L_a$. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are $\leq 0.60\ L_a$ for the Type B and Type C tests and $\leq 0.75\ L_a$ for the Type A tests;

b. Air lock testing acceptance criteria are:

1) Overall air lock leakage rate is $\leq 0.05\ L_a$ when tested at $\geq P_a$.

2) For each door, the leakage rate is $\leq 0.01\ L_a$ when pressurized to ≥ 9.0 psig.

(continued)

5.7 Reporting Requirements (continued)

5.7.2 Special Reports (continued)

1. The scope of inspections performed on each SG,
2. Active degradation mechanisms found,
3. Nondestructive examination techniques utilized for each degradation mechanism,
4. Location, orientation (if linear), and measured sizes (if available) of service induced indications,
5. Number of tubes plugged or repaired during the inspection outage for each active degradation mechanism,
6. Total number and percentage of tubes plugged or repaired to date,
7. The results of condition monitoring, including the results of tube pulls and in-situ testing,
8. The effective plugging percentage for all plugging and tube repairs in each SG, and
9. Repair method utilized and the number of tubes repaired by each repair method.

Attachment B

(Existing Pages)

SONGS Unit 3

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.17 Steam Generator (SG) Tube Integrity

LCO 3.4.17 SG tube integrity shall be maintained.

AND

All SG tubes satisfying the tube repair criteria shall be plugged or repaired in accordance with the Steam Generator Program.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

-----------------------------------NOTE-----------------------------------
Separate Condition entry is allowed for each SG tube.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more SG tubes satisfying the tube repair criteria and not plugged or repaired in accordance with the Steam Generator Program.	A.1 Verify tube integrity of the affected tube(s) is maintained until the next refueling outage or SG tube inspection. AND A.2 Plug or repair the affected tube(s) in accordance with the Steam Generator Program.	7 days Prior to entering MODE 4 following the next refueling outage or SG tube inspection
B. Required Action and associated Completion Time of Condition A not met. OR SG tube integrity not maintained.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.17.1	Verify SG tube integrity in accordance with the Steam Generator Program.	In accordance with the Steam Generator Program
SR 3.4.17.2	Verify that each inspected SG tube that satisfies the tube repair criteria is plugged or repaired in accordance with the Steam Generator Program.	Prior to entering MODE 4 following a SG tube inspection

5.5 Procedures, Programs, and Manuals (continued)

5.5.2.8 Primary Coolant Sources Outside Containment Program (continued)

system (post-accident sampling return piping only until such time as a modification eliminates the post-accident piping as a potential leakage path). The program shall include the following:

a. Preventive maintenance and periodic visual inspection requirements; and

b. Integrated leak test requirements for each system at refueling cycle intervals or less.

5.5.2.9 Pre-Stressed Concrete Containment Tendon Surveillance Program

This program provides controls for monitoring any tendon degradation in pre-stressed concrete containment, including effectiveness of its corrosion protection medium, to ensure containment structural integrity. Program itself is relocated to the LCS.

5.5.2.10 Inservice Inspection and Testing Program

This program provides controls for inservice inspection of ASME Code Class 1, 2, and 3 components and Code Class CC and MC components including applicable supports. The program provides controls for inservice testing of ASME Code Class 1, 2, and 3 components. The program itself is located in the LCS.

5.5.2.11 Steam Generator (SG) Program

A Steam Generator Program shall be established and implemented to ensure that SG tube integrity is maintained. In addition, the Steam Generator Program shall include the following provisions:

a. Provisions for condition monitoring assessments. Condition monitoring assessment means an evaluation of the "as found" condition of the tubing with respect to the performance criteria for structural integrity and accident induced leakage. The "as found" condition refers to the condition of the tubing during an SG inspection outage, as determined from the inservice inspection results or by other means, prior to the plugging or repair of tubes. Condition monitoring assessments shall be conducted during each outage during which the SG tubes are inspected, plugged, or repaired to confirm that the performance criteria are being met.

5.5.2.11 Steam Generator (SG) Program (continued)

c. Provisions for SG tube repair criteria.

1. Tubes shall be plugged or repaired if the non-sleeved region of a tube is found by inservice inspection to contain flaws with a depth equal to or exceeding 44% of the nominal tube wall thickness, at a location that is not addressed in Technical Specification 5.5.2.11.c.2.

2. Tubes shall be plugged or repaired if the non-sleeved region of a tube is found by inservice inspection to contain flaws at either of the following locations:

   a) below the bottom of the hot leg expansion transition or hot leg top of the tubesheet, whichever is higher, or

   b) below the bottom of the cold leg expansion transition or cold leg top of the tubesheet, whichever is higher.

3. Tubes shall be plugged if the sleeved region of a tube is found to contain flaws in the:

   a) sleeve, or

   b) sleeve or original tube wall at a sleeve-to-tube joint.

4. The following C* methodology may be applied in a portion of the expanded tube in the tubesheet region, as an alternative to the repair criteria of Technical Specification 5.5.2.11.c.2. Flaws, in the locations described below, may remain in service regardless of size.

   a) For tubes that have not been repaired in the hot leg tubesheet region: Greater than 10.6 inches below the bottom of the hot leg expansion transition or top of the hot leg tubesheet, whichever is lower.

   b) For tubes that have not been repaired in the cold leg tubesheet region: Greater than 11.0 inches below the bottom of the cold leg expansion transition or top of the cold leg tubesheet, whichever is lower.

5.5.2.11 Steam Generator (SG) Program (continued)

c) For tubes that have been repaired in the hot leg tubesheet region: Below the bottom of the lower sleeve-to-tube joint or greater than 10.6 inches below the bottom of the hot leg expansion transition or greater than 10.6 inches below the top of the hot leg tubesheet, whichever of these three is lowest.

d) For tubes that have been repaired in the cold leg tubesheet region: Below the bottom of the lower sleeve-to-tube joint or greater than 11.0 inches below the bottom of the cold leg expansion transition or greater than 11.0 inches below the top of the cold leg tubesheet, whichever of these three is lowest.

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube repair criteria. The tube-to-tubesheet weld is not part of the tube. In tubes repaired by sleeving, the portion of the original tube wall between the sleeve's joints is not an area requiring re-inspection.

--------------------------NOTE-------------------------------

The requirement for methods of inspection with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube does not apply to the portion of the original tube wall adjacent to the nickel band portion (the lower half) of the lower joint for the repair process that is discussed in Technical Specification (TS) 5.5.2.11.f.1. However, the method of inspection in this area should be a rotating plus point (or equivalent) coil. The SG tube repair criterion of TS 5.5.2.11.c.3.b is applicable to flaws in this area.

In addition to meeting the requirements of d.1, d.2, d.3, and d.4 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. An assessment of degradation shall be performed to determine the

5.5 Procedures, Programs, and Manuals (continued)

5.5.2.11 Steam Generator (SG) Program (continued)

type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

1. Inspect 100% of the tubes in each SG during the first refueling outage following SG replacement.

2. Inspect 100% of the tubes at sequential periods of 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the SGs. No SG shall operate for more than 24 effective full power months or one refueling outage (whichever is less) without being inspected.

3. If crack indications are found in any SG tube, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever is less). If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

4. All sleeves shall be inspected with eddy current prior to initial operation. This includes pressure retaining portions of the parent tube in contact with the sleeve, the sleeve-to-tube weld and the pressure retaining portion of the sleeve.

e. Provisions for monitoring operational primary to secondary LEAKAGE.

f. Provisions for SG tube repair methods. Steam generator tube repair methods shall provide the means to re-establish the RCS pressure boundary integrity of SG tubes without removing the tube from service. For the purposes of these Specifications, tube plugging is not a repair. All acceptable tube repair methods are listed below.

1. TIG welded sleeving with heat treatment, as described in ABB/CE Topical Report, CEN-630-P, Rev. 2, is currently approved by the NRC until December 2010. All sleeves shall be removed from service by December 2010.

   Tube repair can be performed on certain tubes that have been previously plugged as a corrective or preventive measure. A tube inspection of the entire length of the tube shall be performed on a previously plugged tube prior to returning the tube to service.

5.5 Procedures, Programs, and Manuals (continued)

5.5.2.15 Containment Leakage Rate Testing Program

A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995 as modified by the following exception:

NEI 94-01 - 1995, Section 9.2.3: The first Type A Test performed after the September 10, 1995 Type A Test shall be performed no later than September 9, 2010.

The calculated peak containment internal pressure related to the design basis loss-of-coolant accident, P_a, is 45.9 psig (P_a will conservatively be assumed to be equal to the calculated peak containment internal pressure for the design basis Main Steam Line Break (56.5 psig) for the purpose of containment testing in accordance with this Technical Specification).

The maximum allowable containment leakage rate, L_a, at P_a, shall be 0.10% of containment air weight per day.

Leakage rate acceptance criteria are:

a. The Containment overall leakage rate acceptance criterion is $\leq 1.0\ L_a$. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are $\leq 0.60\ L_a$ for the Type B and Type C tests and $\leq 0.75\ L_a$ for the Type A tests;

b. Air lock testing acceptance criteria are:

1) Overall air lock leakage rate is $\leq 0.05\ L_a$ when tested at $\geq P_a$.

2) For each door, the leakage rate is $\leq 0.01\ L_a$ when pressurized to ≥ 9.0 psig.

(continued)

5.7 Reporting Requirements (continued)

5.7.2 Special Reports (continued)

1. The scope of inspections performed on each SG,
2. Active degradation mechanisms found,
3. Nondestructive examination techniques utilized for each degradation mechanism,
4. Location, orientation (if linear), and measured sizes (if available) of service induced indications,
5. Number of tubes plugged or repaired during the inspection outage for each active degradation mechanism,
6. Total number and percentage of tubes plugged or repaired to date,
7. The results of condition monitoring, including the results of tube pulls and in-situ testing,
8. The effective plugging percentage for all plugging and tube repairs in each SG, and
9. Repair method utilized and the number of tubes repaired by each repair method.

Attachment C

(Proposed Pages)

(Redline and Strikeout)

SONGS Unit 2

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.17 Steam Generator (SG) Tube Integrity

LCO 3.4.17 SG tube integrity shall be maintained.

AND

All SG tubes satisfying the tube repair criteria shall be plugged ~~or repaired~~ in accordance with the Steam Generator Program.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

-----------------------------------NOTE-----------------------------------
Separate Condition entry is allowed for each SG tube.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more SG tubes satisfying the tube repair criteria and not plugged ~~or repaired~~ in accordance with the Steam Generator Program.	A.1 Verify tube integrity of the affected tube(s) is maintained until the next refueling outage or SG tube inspection.	7 days
	AND	
	A.2 Plug ~~or repair~~ the affected tube(s) in accordance with the Steam Generator Program.	Prior to entering MODE 4 following the next refueling outage or SG tube inspection
B. Required Action and associated Completion Time of Condition A not met. OR SG tube integrity not maintained.	B.1 Be in MODE 3.	6 hours
	AND	
	B.2 Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.17.1	Verify SG tube integrity in accordance with the Steam Generator Program.	In accordance with the Steam Generator Program
SR 3.4.17.2	Verify that each inspected SG tube that satisfies the tube repair criteria is plugged ~~or repaired~~ in accordance with the Steam Generator Program.	Prior to entering MODE 4 following a SG tube inspection

5.5.2.8 Primary Coolant Sources Outside Containment Program (continued)

system (post-accident sampling return piping only until such time as a modification eliminates the post-accident piping as a potential leakage path). The program shall include the following:

a. Preventive maintenance and periodic visual inspection requirements; and

b. Integrated leak test requirements for each system at refueling cycle intervals or less.

5.5.2.9 Pre-Stressed Concrete Containment Tendon Surveillance Program

This program provides controls for monitoring any tendon degradation in pre-stressed concrete containment, including effectiveness of its corrosion protection medium, to ensure containment structural integrity. Program itself is relocated to the LCS.

5.5.2.10 Inservice Inspection and Testing Program

This program provides controls for inservice inspection of ASME Code Class 1, 2, and 3 components and Code Class CC and MC components including applicable supports. The program provides controls for inservice testing of ASME Code Class 1, 2, and 3 components. The program itself is located in the LCS.

5.5.2.11 Steam Generator (SG) Program

A Steam Generator Program shall be established and implemented to ensure that SG tube integrity is maintained. In addition, the Steam Generator Program shall include the following provisions:

a. Provisions for condition monitoring assessments. Condition monitoring assessment means an evaluation of the "as found" condition of the tubing with respect to the performance criteria for structural integrity and accident induced leakage. The "as found" condition refers to the condition of the tubing during an SG inspection outage, as determined from the inservice inspection results or by other means, prior to the plugging ~~or repair~~ of tubes. Condition monitoring assessments shall be conducted during each outage during which the SG tubes are inspected~~,~~ or plugged, ~~or repaired~~ to confirm that the performance criteria are being met.

5.5 Procedures, Programs, and Manuals (continued)

5.5.2.11 Steam Generator (SG) Program (continued)

c. Provisions for SG tube repair criteria.

1. Tubes ~~shall be plugged or repaired if the non-sleeved region of a tube is~~ found by inservice inspection to contain flaws with a depth equal to or exceeding ~~44%~~ 35% of the nominal tube wall thickness~~, at a location that is not addressed in Technical Specification 5.5.2.11.c.2~~ shall be plugged.

~~2. Tubes shall be plugged or repaired if the non-sleeved region of a tube is found by inservice inspection to contain flaws at either of the following locations:~~

~~a) below the bottom of the hot leg expansion transition or hot leg top of the tubesheet, whichever is higher, or~~

~~b) below the bottom of the cold leg expansion transition or cold leg top of the tubesheet, whichever is higher.~~

~~3. Tubes shall be plugged if the sleeved region of a tube is found to contain flaws in the:~~

~~a) sleeve, or~~

~~b) sleeve or original tube wall at a sleeve-to-tube joint.~~

~~4. The following C* methodology may be applied in a portion of the expanded tube in the tubesheet region, as an alternative to the repair criteria of Technical Specification 5.5.2.11.c.2. Flaws, in the locations described below, may remain in service regardless of size.~~

~~a) For tubes that have not been repaired in the hot leg tubesheet region: Greater than 10.6 inches below the bottom of the hot leg expansion transition or top of the hot leg tubesheet, whichever is lower.~~

~~b) For tubes that have not been repaired in the cold leg tubesheet region: Greater than 11.0 inches below the bottom of the cold leg expansion transition or top of the cold leg tubesheet, whichever is lower.~~

5.5 Procedures, Programs, and Manuals (continued)

5.5.2.11 Steam Generator (SG) Program (continued)

~~c) For tubes that have been repaired in the hot leg tubesheet region: Below the bottom of the lower sleeve-to-tube joint or greater than 10.6 inches below the bottom of the hot leg expansion transition or greater than 10.6 inches below the top of the hot leg tubesheet, whichever of these three is lowest.~~

~~d) For tubes that have been repaired in the cold leg tubesheet region: Below the bottom of the lower sleeve-to-tube joint or greater than 11.0 inches below the bottom of the cold leg expansion transition or greater than 11.0 inches below the top of the cold leg tubesheet, whichever of these three is lowest.~~

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube repair criteria. The tube-to-tubesheet weld is not part of the tube. ~~In tubes repaired by sleeving, the portion of the original tube wall between the sleeve's joints is not an area requiring re-inspection.~~

~~NOTE~~

~~The requirement for methods of inspection with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube does not apply to the portion of the original tube wall adjacent to the nickel band portion (the lower half) of the lower joint for the repair process that is discussed in Technical Specification (TS) 5.5.2.11.f.1. However, the method of inspection in this area should be a rotating plus point (or equivalent) coil. The SG tube repair criterion of TS 5.5.2.11.c.3.b is applicable to flaws in this area.~~

In addition to meeting the requirements of d.1, d.2, ~~d.3,~~ and d.~~4~~ 3 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. An assessment of degradation shall be performed to determine the

5.5 Procedures, Programs, and Manuals (continued)

5.5.2.11 Steam Generator (SG) Program (continued)

type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

1. Inspect 100% of the tubes in each SG during the first refueling outage following SG replacement.

~~2. Inspect 100% of the tubes at sequential periods of 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the SGs. No SG shall operate for more than 24 effective full power months or one refueling outage (whichever is less) without being inspected.~~

2. Inspect 100% of the tubes at sequential periods of 144, 108, 72, and thereafter, 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the SGs. In addition, inspect 50% of the tubes by the refueling outage nearest the midpoint of the period and the remaining 50% by the refueling outage nearest the end of the period. No SG shall operate for more than 72 effective full power months or three refueling outages (whichever is less) without being inspected.

3. If crack indications are found in any SG tube, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever is less). If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

~~4. All sleeves shall be inspected with eddy current prior to initial operation. This includes pressure retaining portions of the parent tube in contact with the sleeve, the sleeve-to-tube weld and the pressure retaining portion of the sleeve.~~

e. Provisions for monitoring operational primary to secondary LEAKAGE.

~~f. Provisions for SG tube repair methods. Steam generator tube repair methods shall provide the means to re-establish the RCS pressure boundary integrity of SG tubes without removing the tube from service. For the purposes of these Specifications, tube plugging is not a repair. All acceptable tube repair methods are listed below.~~

5.5 Procedures, Programs, and Manuals (continued)

~~1. TIG welded sleeving with heat treatment, as described in ABB/CE Topical Report, CEN-630-P, Rev. 2, is currently approved by the NRC until December 2009. All sleeves shall be removed from service by December 2009.~~

~~Tube repair can be performed on certain tubes that have been previously plugged as a corrective or preventive measure. A tube inspection of the entire length of the tube shall be performed on a previously plugged tube prior to returning the tube to service.~~

5.5.2.15 Containment Leakage Rate Testing Program

A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995 as modified by the following exception:

NEI 94-01 - 1995, Section 9.2.3: The first Type A Test performed after the March 31, 1995 Type A Test shall be performed no later than March 30, 2010.

The calculated peak containment internal pressure related to the design basis loss-of-coolant accident, P_a, is ~~45.9~~ 48.0 psig (P_a will conservatively be assumed to be equal to the calculated peak containment internal pressure for the design basis Main Steam Line Break (~~56.5~~ 51.5 psig) for the purpose of containment testing in accordance with this Technical Specification).

The maximum allowable containment leakage rate, L_a, at P_a, shall be 0.10% of containment air weight per day.

Leakage rate acceptance criteria are:

a. The Containment overall leakage rate acceptance criterion is $\leq 1.0\ L_a$. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are $\leq 0.60\ L_a$ for the Type B and Type C tests and $\leq 0.75\ L_a$ for the Type A tests;

b. Air lock testing acceptance criteria are:

1) Overall air lock leakage rate is $\leq 0.05\ L_a$ when tested at $\geq P_a$.

2) For each door, the leakage rate is $\leq 0.01\ L_a$ when pressurized to ≥ 9.0 psig.

(continued)

5.7 Reporting Requirements (continued)

5.7.2 Special Reports (continued)

1. The scope of inspections performed on each SG,

2. Active degradation mechanisms found,

3. Nondestructive examination techniques utilized for each degradation mechanism,

4. Location, orientation (if linear), and measured sizes (if available) of service induced indications,

5. Number of tubes plugged ~~or repaired~~ during the inspection outage for each active degradation mechanism,

6. Total number and percentage of tubes plugged ~~or repaired~~ to date,

7. The results of condition monitoring, including the results of tube pulls and in-situ testing~~,~~ .

~~8. The effective plugging percentage for all plugging and tube repairs in each SG, and~~

~~9. Repair method utilized and the number of tubes repaired by each repair method.~~

Attachment D

(Proposed Pages)

(Redline and Strikeout)

SONGS Unit 3

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.17 Steam Generator (SG) Tube Integrity

LCO 3.4.17 SG tube integrity shall be maintained.

AND

All SG tubes satisfying the tube repair criteria shall be plugged ~~or repaired~~ in accordance with the Steam Generator Program.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

-----------------------------------NOTE-----------------------------------
Separate Condition entry is allowed for each SG tube.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more SG tubes satisfying the tube repair criteria and not plugged ~~or repaired~~ in accordance with the Steam Generator Program.	A.1 Verify tube integrity of the affected tube(s) is maintained until the next refueling outage or SG tube inspection.	7 days
	AND	
	A.2 Plug ~~or repair~~ the affected tube(s) in accordance with the Steam Generator Program.	Prior to entering MODE 4 following the next refueling outage or SG tube inspection
B. Required Action and associated Completion Time of Condition A not met. OR SG tube integrity not maintained.	B.1 Be in MODE 3.	6 hours
	AND	
	B.2 Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.17.1	Verify SG tube integrity in accordance with the Steam Generator Program.	In accordance with the Steam Generator Program
SR 3.4.17.2	Verify that each inspected SG tube that satisfies the tube repair criteria is plugged ~~or repaired~~ in accordance with the Steam Generator Program.	Prior to entering MODE 4 following a SG tube inspection

5.5 Procedures, Programs, and Manuals (continued)

5.5.2.8 Primary Coolant Sources Outside Containment Program (continued)

system (post-accident sampling return piping only until such time as a modification eliminates the post-accident piping as a potential leakage path). The program shall include the following:

a. Preventive maintenance and periodic visual inspection requirements; and

b. Integrated leak test requirements for each system at refueling cycle intervals or less.

5.5.2.9 Pre-Stressed Concrete Containment Tendon Surveillance Program

This program provides controls for monitoring any tendon degradation in pre-stressed concrete containment, including effectiveness of its corrosion protection medium, to ensure containment structural integrity. Program itself is relocated to the LCS.

5.5.2.10 *Inservice Inspection and Testing Program*

This program provides controls for inservice inspection of ASME Code Class 1, 2, and 3 components and Code Class CC and MC components including applicable supports. The program provides controls for inservice testing of ASME Code Class 1, 2, and 3 components. The program itself is located in the LCS.

5.5.2.11 Steam Generator (SG) Program

A Steam Generator Program shall be established and implemented to ensure that SG tube integrity is maintained. In addition, the Steam Generator Program shall include the following provisions:

a. Provisions for condition monitoring assessments. Condition monitoring assessment means an evaluation of the "as found" condition of the tubing with respect to the performance criteria for structural integrity and accident induced leakage. The "as found" condition refers to the condition of the tubing during an SG inspection outage, as determined from the inservice inspection results or by other means, prior to the plugging ~~or repair~~ of tubes. Condition monitoring assessments shall be conducted during each outage during which the SG tubes are inspected~~,~~ or plugged, ~~or repaired~~ to confirm that the performance criteria are being met.

5.5 Procedures, Programs, and Manuals (continued)

5.5.2.11 Steam Generator (SG) Program (continued)

c. Provisions for SG tube repair criteria.

1. Tubes ~~shall be plugged or repaired if the non-sleeved region of a tube is~~ found by inservice inspection to contain flaws with a depth equal to or exceeding ~~44%~~ 35% of the nominal tube wall thickness~~, at a location that is not addressed in Technical Specification 5.5.2.11.c.2~~ shall be plugged.

~~2. Tubes shall be plugged or repaired if the non-sleeved region of a tube is found by inservice inspection to contain flaws at either of the following locations:~~

   ~~a) below the bottom of the hot leg expansion transition or hot leg top of the tubesheet, whichever is higher, or~~

   ~~b) below the bottom of the cold leg expansion transition or cold leg top of the tubesheet, whichever is higher.~~

~~3. Tubes shall be plugged if the sleeved region of a tube is found to contain flaws in the:~~

   ~~a) sleeve, or~~

   ~~b) sleeve or original tube wall at a sleeve-to-tube joint.~~

~~4. The following C* methodology may be applied in a portion of the expanded tube in the tubesheet region, as an alternative to the repair criteria of Technical Specification 5.5.2.11.c.2. Flaws, in the locations described below, may remain in service regardless of size.~~

   ~~a) For tubes that have not been repaired in the hot leg tubesheet region: Greater than 10.6 inches below the bottom of the hot leg expansion transition or top of the hot leg tubesheet, whichever is lower.~~

   ~~b) For tubes that have not been repaired in the cold leg tubesheet region: Greater than 11.0 inches below the bottom of the cold leg expansion transition or top of the cold leg tubesheet, whichever is lower.~~

5.5 Procedures, Programs, and Manuals (continued)

5.5.2.11 Steam Generator (SG) Program (continued)

~~c) For tubes that have been repaired in the hot leg tubesheet region: Below the bottom of the lower sleeve-to-tube joint or greater than 10.6 inches below the bottom of the hot leg expansion transition or greater than 10.6 inches below the top of the hot leg tubesheet, whichever of these three is lowest.~~

~~d) For tubes that have been repaired in the cold leg tubesheet region: Below the bottom of the lower sleeve-to-tube joint or greater than 11.0 inches below the bottom of the cold leg expansion transition or greater than 11.0 inches below the top of the cold leg tubesheet, whichever of these three is lowest.~~

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube repair criteria. The tube-to-tubesheet weld is not part of the tube. ~~In tubes repaired by sleeving, the portion of the original tube wall between the sleeve's joints is not an area requiring re-inspection.~~

~~NOTE~~

~~The requirement for methods of inspection with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube does not apply to the portion of the original tube wall adjacent to the nickel band portion (the lower half) of the lower joint for the repair process that is discussed in Technical Specification (TS) 5.5.2.11.f.1. However, the method of inspection in this area should be a rotating plus point (or equivalent) coil. The SG tube repair criterion of TS 5.5.2.11.c.3.b is applicable to flaws in this area.~~

In addition to meeting the requirements of d.1, d.2, ~~d.3,~~ and d.~~4~~3 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. An assessment of degradation shall be performed to determine the

5.5.2.11 Steam Generator (SG) Program (continued)

type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

1. Inspect 100% of the tubes in each SG during the first refueling outage following SG replacement.

~~2. Inspect 100% of the tubes at sequential periods of 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the SGs. No SG shall operate for more than 24 effective full power months or one refueling outage (whichever is less) without being inspected.~~

2. Inspect 100% of the tubes at sequential periods of 144, 108, 72, and thereafter, 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the SGs. In addition, inspect 50% of the tubes by the refueling outage nearest the midpoint of the period and the remaining 50% by the refueling outage nearest the end of the period. No SG shall operate for more than 72 effective full power months or three refueling outages (whichever is less) without being inspected.

3. If crack indications are found in any SG tube, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever is less). If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

~~4. All sleeves shall be inspected with eddy current prior to initial operation. This includes pressure retaining portions of the parent tube in contact with the sleeve, the sleeve-to-tube weld and the pressure retaining portion of the sleeve.~~

e. Provisions for monitoring operational primary to secondary LEAKAGE.

~~f. Provisions for SG tube repair methods. Steam generator tube repair methods shall provide the means to re-establish the RCS pressure boundary integrity of SG tubes without removing the tube from service. For the purposes of these Specifications, tube plugging is not a repair. All acceptable tube repair methods are listed below.~~

5.5 Procedures, Programs, and Manuals (continued)

~~1. TIG welded sleeving with heat treatment, as described in ABB/CE Topical Report, CEN-630-P, Rev. 2, is currently approved by the NRC until December 2010. All sleeves shall be removed from service by December 2010.~~

~~Tube repair can be performed on certain tubes that have been previously plugged as a corrective or preventive measure. A tube inspection of the entire length of the tube shall be performed on a previously plugged tube prior to returning the tube to service.~~

5.5 Procedures, Programs, and Manuals (continued)

5.5.2.15 Containment Leakage Rate Testing Program

A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995 as modified by the following exception:

NEI 94-01 - 1995, Section 9.2.3: The first Type A Test performed after the September 10, 1995 Type A Test shall be performed no later than September 9, 2010.

The calculated peak containment internal pressure ~~related~~ to the design basis loss-of-coolant accident, P_a, is ~~45.9~~ 48.0 psig (P_a will conservatively be assumed to be equal to the ~~calculated~~ peak containment ~~internal~~ pressure for the design basis Main Steam Line Break (~~56.5~~ 51.5 psig) for the purpose of containment testing in accordance ~~with~~ this Technical Specification).

The maximum allowable containment leakage rate, L_a, at P_a, shall be 0.10% of containment air weight per day.

Leakage rate acceptance criteria are:

a. The Containment overall leakage rate acceptance criterion is $\leq 1.0\ L_a$. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are $\leq 0.60\ L_a$ for the Type B and Type C tests and $\leq 0.75\ L_a$ for the Type A tests;

b. Air lock testing acceptance criteria are:

1) Overall air lock leakage rate is $\leq 0.05\ L_a$ when tested at $\geq P_a$.

2) For each door, the leakage rate is $\leq 0.01\ L_a$ when pressurized to ≥ 9.0 psig.

(continued)

5.7 Reporting Requirements (continued)

5.7.2 Special Reports (continued)

1. The scope of inspections performed on each SG,

2. Active degradation mechanisms found,

3. Nondestructive examination techniques utilized for each degradation mechanism,

4. Location, orientation (if linear), and measured sizes (if available) of service induced indications,

5. Number of tubes plugged ~~or repaired~~ during the inspection outage for each active degradation mechanism,

6. Total number and percentage of tubes plugged ~~or repaired~~ to date,

7. The results of condition monitoring, including the results of tube pulls and in-situ testing.

~~8. The effective plugging percentage for all plugging and tube repairs in each SG, and~~

~~9. Repair method utilized and the number of tubes repaired by each repair method.~~

Attachment E

(Proposed Pages)

SONGS Unit 2

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.17 Steam Generator (SG) Tube Integrity

LCO 3.4.17 SG tube integrity shall be maintained.

AND

All SG tubes satisfying the tube repair criteria shall be plugged in accordance with the Steam Generator Program.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

-----NOTE-----
Separate Condition entry is allowed for each SG tube.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more SG tubes satisfying the tube repair criteria and not plugged in accordance with the Steam Generator Program.	A.1 Verify tube integrity of the affected tube(s) is maintained until the next refueling outage or SG tube inspection. AND A.2 Plug the affected tube(s) in accordance with the Steam Generator Program.	7 days Prior to entering MODE 4 following the next refueling outage or SG tube inspection
B. Required Action and associated Completion Time of Condition A not met. OR SG tube integrity not maintained.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.17.1	Verify SG tube integrity in accordance with the Steam Generator Program.	In accordance with the Steam Generator Program
SR 3.4.17.2	Verify that each inspected SG tube that satisfies the tube repair criteria is plugged in accordance with the Steam Generator Program.	Prior to entering MODE 4 following a SG tube inspection

5.5.2.8 Primary Coolant Sources Outside Containment Program (continued)

system (post-accident sampling return piping only until such time as a modification eliminates the post-accident piping as a potential leakage path). The program shall include the following:

a. Preventive maintenance and periodic visual inspection requirements; and

b. Integrated leak test requirements for each system at refueling cycle intervals or less.

5.5.2.9 Pre-Stressed Concrete Containment Tendon Surveillance Program

This program provides controls for monitoring any tendon degradation in pre-stressed concrete containment, including effectiveness of its corrosion protection medium, to ensure containment structural integrity. Program itself is relocated to the LCS.

5.5.2.10 Inservice Inspection and Testing Program

This program provides controls for inservice inspection of ASME Code Class 1, 2, and 3 components and Code Class CC and MC components including applicable supports. The program provides controls for inservice testing of ASME Code Class 1, 2, and 3 components. The program itself is located in the LCS.

5.5.2.11 Steam Generator (SG) Program

A Steam Generator Program shall be established and implemented to ensure that SG tube integrity is maintained. In addition, the Steam Generator Program shall include the following provisions:

a. Provisions for condition monitoring assessments. Condition monitoring assessment means an evaluation of the "as found" condition of the tubing with respect to the performance criteria for structural integrity and accident induced leakage. The "as found" condition refers to the condition of the tubing during an SG inspection outage, as determined from the inservice inspection results or by other means, prior to the plugging of tubes. Condition monitoring assessments shall be conducted during each outage during which the SG tubes are inspected or plugged, to confirm that the performance criteria are being met.

5.5 Procedures, Programs, and Manuals (continued)

5.5.2.11 Steam Generator (SG) Program (continued)

c. Provisions for SG tube repair criteria.

1. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 35% of the nominal tube wall thickness shall be plugged.

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube repair criteria. The tube-to-tubesheet weld is not part of the tube.

In addition to meeting the requirements of d.1, d.2, and d.3 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. An assessment of degradation shall be performed to determine the type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

1. Inspect 100% of the tubes in each SG during the first refueling outage following SG replacement.

2. Inspect 100% of the tubes at sequential periods of 144, 108, 72, and thereafter, 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the SGs. In addition, inspect 50% of the tubes by the refueling outage nearest the midpoint of the period and the remaining 50% by the refueling outage nearest the end of the period. No SG shall operate for more than 72 effective full power months or three refueling outages (whichever is less) without being inspected.

3. If crack indications are found in any SG tube, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever is less). If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

e. Provisions for monitoring operational primary to secondary LEAKAGE.

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5.5.2.15 Containment Leakage Rate Testing Program

A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995 as modified by the following exception:

NEI 94-01 - 1995, Section 9.2.3: The first Type A Test performed after the March 31, 1995 Type A Test shall be performed no later than March 30, 2010.

The calculated peak containment internal pressure related to the design basis loss-of-coolant accident, P_a, is 48.0 psig (P_a will conservatively be assumed to be equal to the calculated peak containment internal pressure for the design basis Main Steam Line Break (51.5 psig) for the purpose of containment testing in accordance with this Technical Specification).

The maximum allowable containment leakage rate, L_a, at P_a, shall be 0.10% of containment air weight per day.

Leakage rate acceptance criteria are:

a. The Containment overall leakage rate acceptance criterion is $\leq 1.0\ L_a$. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are $\leq 0.60\ L_a$ for the Type B and Type C tests and $\leq 0.75\ L_a$ for the Type A tests;

b. Air lock testing acceptance criteria are:

   1) Overall air lock leakage rate is $\leq 0.05\ L_a$ when tested at $\geq P_a$.

   2) For each door, the leakage rate is $\leq 0.01\ L_a$ when pressurized to ≥ 9.0 psig.

(continued)

5.7 Reporting Requirements (continued)

5.7.2 Special Reports (continued)

1. The scope of inspections performed on each SG,

2. Active degradation mechanisms found,

3. Nondestructive examination techniques utilized for each degradation mechanism,

4. Location, orientation (if linear), and measured sizes (if available) of service induced indications,

5. Number of tubes plugged during the inspection outage for each active degradation mechanism,

6. Total number and percentage of tubes plugged to date,

7. The results of condition monitoring, including the results of tube pulls and in-situ testing.

Attachment F

(Proposed Pages)

SONGS Unit 3

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.17 Steam Generator (SG) Tube Integrity

LCO 3.4.17 SG tube integrity shall be maintained.

AND

All SG tubes satisfying the tube repair criteria shall be plugged in accordance with the Steam Generator Program.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTIONS

-----NOTE-----
Separate Condition entry is allowed for each SG tube.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more SG tubes satisfying the tube repair criteria and not plugged in accordance with the Steam Generator Program.	A.1 Verify tube integrity of the affected tube(s) is maintained until the next refueling outage or SG tube inspection.	7 days
	AND	
	A.2 Plug the affected tube(s) in accordance with the Steam Generator Program.	Prior to entering MODE 4 following the next refueling outage or SG tube inspection
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3.	6 hours
OR	AND	
SG tube integrity not maintained.	B.2 Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.17.1	Verify SG tube integrity in accordance with the Steam Generator Program.	In accordance with the Steam Generator Program
SR 3.4.17.2	Verify that each inspected SG tube that satisfies the tube repair criteria is plugged in accordance with the Steam Generator Program.	Prior to entering MODE 4 following a SG tube inspection

5.5 Procedures, Programs, and Manuals (continued)

5.5.2.8 Primary Coolant Sources Outside Containment Program (continued)

system (post-accident sampling return piping only until such time as a modification eliminates the post-accident piping as a potential leakage path). The program shall include the following:

a. Preventive maintenance and periodic visual inspection requirements; and

b. Integrated leak test requirements for each system at refueling cycle intervals or less.

5.5.2.9 Pre-Stressed Concrete Containment Tendon Surveillance Program

This program provides controls for monitoring any tendon degradation in pre-stressed concrete containment, including effectiveness of its corrosion protection medium, to ensure containment structural integrity. Program itself is relocated to the LCS.

5.5.2.10 Inservice Inspection and Testing Program

This program provides controls for inservice inspection of ASME Code Class 1, 2, and 3 components and Code Class CC and MC components including applicable supports. The program provides controls for inservice testing of ASME Code Class 1, 2, and 3 components. The program itself is located in the LCS.

5.5.2.11 Steam Generator (SG) Program

A Steam Generator Program shall be established and implemented to ensure that SG tube integrity is maintained. In addition, the Steam Generator Program shall include the following provisions:

a. Provisions for condition monitoring assessments. Condition monitoring assessment means an evaluation of the "as found" condition of the tubing with respect to the performance criteria for structural integrity and accident induced leakage. The "as found" condition refers to the condition of the tubing during an SG inspection outage, as determined from the inservice inspection results or by other means, prior to the plugging of tubes. Condition monitoring assessments shall be conducted during each outage during which the SG tubes are inspected or plugged, to confirm that the performance criteria are being met.

5.5 Procedures, Programs, and Manuals (continued)

5.5.2.11 Steam Generator (SG) Program (continued)

c. Provisions for SG tube repair criteria.

1. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 35% of the nominal tube wall thickness shall be plugged.

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube repair criteria. The tube-to-tubesheet weld is not part of the tube.

In addition to meeting the requirements of d.1, d.2, and d.3 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. An assessment of degradation shall be performed to determine the type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

1. Inspect 100% of the tubes in each SG during the first refueling outage following SG replacement.

2. Inspect 100% of the tubes at sequential periods of 144, 108, 72, and thereafter, 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the SGs. In addition, inspect 50% of the tubes by the refueling outage nearest the midpoint of the period and the remaining 50% by the refueling outage nearest the end of the period. No SG shall operate for more than 72 effective full power months or three refueling outages (whichever is less) without being inspected.

3. If crack indications are found in any SG tube, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever is less). If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

e. Provisions for monitoring operational primary to secondary LEAKAGE.

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5.5 Procedures, Programs, and Manuals (continued)

5.5.2.15 Containment Leakage Rate Testing Program

A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995 as modified by the following exception:

NEI 94-01 - 1995, Section 9.2.3: The first Type A Test performed after the September 10, 1995 Type A Test shall be performed no later than September 9, 2010.

The calculated peak containment internal pressure related to the design basis loss-of-coolant accident, P_a, is 48.0 psig (P_a will conservatively be assumed to be equal to the calculated peak containment internal pressure for the design basis Main Steam Line Break (51.5 psig) for the purpose of containment testing in accordance with this Technical Specification).

The maximum allowable containment leakage rate, L_a, at P_a, shall be 0.10% of containment air weight per day.

Leakage rate acceptance criteria are:

a. The Containment overall leakage rate acceptance criterion is $\leq 1.0\ L_a$. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are $\leq 0.60\ L_a$ for the Type B and Type C tests and $\leq 0.75\ L_a$ for the Type A tests;

b. Air lock testing acceptance criteria are:

   1) Overall air lock leakage rate is $\leq 0.05\ L_a$ when tested at $\geq P_a$.

   2) For each door, the leakage rate is $\leq 0.01\ L_a$ when pressurized to $\geq$ 9.0 psig.

(continued)

5.7 Reporting Requirements (continued)

5.7.2 Special Reports (continued)

1. The scope of inspections performed on each SG,
2. Active degradation mechanisms found,
3. Nondestructive examination techniques utilized for each degradation mechanism,
4. Location, orientation (if linear), and measured sizes (if available) of service induced indications,
5. Number of tubes plugged during the inspection outage for each active degradation mechanism,
6. Total number and percentage of tubes plugged to date,
7. The results of condition monitoring, including the results of tube pulls and in-situ testing.

Attachment G

(Proposed Bases Pages)

SONGS Unit 2

(for information only)

BASES (continued)

BACKGROUND (continued)	the SG performance criteria provides reasonable assurance of maintaining tube integrity at normal and accident conditions. The processes used to meet the SG performance criteria are defined by the Steam Generator Program Guidelines (Ref. 1).
APPLICABLE SAFETY ANALYSES	The Steam Generator Tube Rupture (SGTR) accident is the limiting design basis event for SG tubes and avoiding an SGTR is the basis for this Specification. The analysis of a SGTR event assumes a bounding primary to secondary LEAKAGE rate equal to 0.5 gallons per minute (720 gallons per day) to each SG, plus the leakage rate associated with a double-ended rupture of a single tube. The analysis for design basis accidents and transients other than a SGTR assume the SG tubes retain their structural integrity (i.e., they are assumed not to rupture). In these analyses, the steam discharge to the atmosphere is based on a primary to secondary LEAKAGE from each SG of 0.5 gallons per minute or is assumed to increase to 0.5 gallons per minute as a result of accident induced conditions. For accidents that do not involve fuel damage, the primary coolant activity level of DOSE EQUIVALENT I-131 is assumed to be equal to the LCO 3.4.16, "RCS Specific Activity," limits. For accidents that assume fuel damage, the primary coolant activity is a function of the amount of activity released from the damaged fuel. The dose consequences of these events are within the limits of GDC 19 (Ref.2), 10 CFR 100 (Ref. 3) or the NRC approved licensing basis (e.g., a small fraction of these limits). Steam Generator tube integrity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	The LCO requires that SG tube integrity be maintained. The LCO also requires that all SG tubes that satisfy the repair criteria be plugged ~~or repaired~~ in accordance with the Steam Generator Program. During an SG inspection, any inspected tube that satisfies the Steam Generator Program repair criteria is ~~repaired or~~ removed from service by plugging. If a tube was determined to satisfy the repair criteria but was not plugged ~~or repaired~~, the tube may still have tube integrity.

(continued)

BASES (continued)

LCO (continued)

In the context of this Specification, a SG tube is defined as the entire length of the tube, including the tube wall ~~and any repairs made to it~~, between the tube-to-tubesheet weld at the tube inlet and the tube-to-tubesheet weld at the tube outlet. The tube-to-tubesheet weld is not considered part of the tube.

A SG tube has tube integrity when it satisfies the SG performance criteria. The SG performance criteria are defined in Specification 5.5.2.11, "Steam Generator Program," and describe acceptable SG tube performance. The Steam Generator Program also provides the evaluation process for determining conformance with the SG performance criteria.

There are three SG performance criteria: structural integrity, accident induced leakage, and operational LEAKAGE. Failure to meet any one of these criteria is considered failure to meet the LCO.

The structural integrity performance criterion provides a margin of safety against tube burst or collapse under normal and accident conditions, and ensures structural integrity of the SG tubes under all anticipated transients included in the design specification. Tube burst is defined as, "The gross structural failure of the tube wall. The condition typically corresponds to an unstable opening displacement (e.g., opening area increased in response to constant pressure) accompanied by ductile (plastic) tearing of the tube material at the ends of the degradation". Tube collapse is defined as, "For the load displacement curve for a given structure, collapse occurs at the top of the load versus displacement curve where the slope of the curve becomes zero". The structural integrity performance criterion provides guidance on assessing loads that have a significant effect on burst or collapse. In that context, the term "significant" is defined as "An accident loading condition other than differential pressure is considered significant when the addition of such loads in the assessment of the structural integrity performance criterion could cause a lower structural limit or limiting burst/collapse condition to be established." For tube integrity evaluations, except for circumferential degradation, axial thermal loads are classified as secondary loads. For circumferential degradation, the classification

(continued)

ACTIONS

The ACTIONS are modified by a Note clarifying that the Conditions may be entered independently for each SG tube. This is acceptable because the Required Actions provide appropriate compensatory actions for each affected SG tube. Complying with the Required Actions may allow for continued operation, and subsequent affected SG tubes are governed by subsequent Condition entry and application of associated Required Actions.

Condition A applies if it is discovered that one or more SG tubes examined in an inservice inspection satisfy the tube repair criteria but were not plugged ~~or repaired~~ in accordance with the Steam Generator Program as required by SR 3.4.17.2. An evaluation of SG tube integrity of the affected tube(s) must be made. Steam Generator tube integrity is based on meeting the SG performance criteria described in the Steam Generator Program. The SG repair criteria define limits on SG tube degradation that allow for flaw growth between inspections while still providing assurance that the SG performance criteria will continue to be met. In order to determine if a SG tube that should have been plugged ~~or repaired~~ has tube integrity, an evaluation must be completed that demonstrates that the SG performance criteria will continue to be met until the next refueling outage or SG tube inspection. The tube integrity determination is based on the estimated condition of the tube at the time the situation is discovered and the estimated growth of the degradation prior to the next SG tube inspection. If it is determined that tube integrity is not being maintained, Condition B applies.

A Completion Time of 7 days is sufficient to complete the evaluation while minimizing the risk of plant operation with a SG tube that may not have tube integrity.

If the evaluation determines that the affected tube(s) have tube integrity, Required Action A.2 allows plant operation to continue until the next refueling outage or SG inspection provided the inspection interval continues to be supported by an operational assessment that reflects the affected tubes. However, the affected tube(s) must be plugged ~~or repaired~~ prior to entering MODE 4 following the next refueling outage or SG inspection. This Completion Time is acceptable since operation until the next inspection is supported by the operational assessment.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.17.1 (continued)

The Steam Generator Program defines the Frequency of SR 3.4.17.1. The Frequency is determined by the operational assessment and other limits in the SG examination guidelines (Ref. 6). The Steam Generator Program uses information on existing degradations and growth rates to determine an inspection Frequency that provides reasonable assurance that the tubing will meet the SG performance criteria at the next scheduled inspection. In addition, Specification 5.5.2.11 contains prescriptive requirements concerning inspection intervals to provide added assurance that the SG performance criteria will be met between scheduled inspections.

SR 3.4.17.2

During an SG inspection, any inspected tube that satisfies the Steam Generator Program repair criteria is ~~repaired or~~ removed from service by plugging. The tube repair criteria delineated in Specification 5.5.2.11 are intended to ensure that tubes accepted for continued service satisfy the SG performance criteria with allowance for error in the flaw size measurement and for future flaw growth. In addition, the tube repair criteria, in conjunction with other elements of the Steam Generator Program, ensure that the SG performance criteria will continue to be met until the next inspection of the subject tube(s). Reference 1 provides guidance for performing operational assessments to verify that the tubes remaining in service will continue to meet the SG performance criteria.

~~Steam Generator tube repairs are only performed using approved repair methods as described in the Steam Generator Program.~~

The frequency of prior to entering MODE 4 following a SG inspection ensures that the Surveillance has been completed and all tubes meeting the repair criteria are plugged ~~or repaired~~ prior to subjecting the SG tubes to significant primary to secondary pressure differential.

(continued)

BASES (continued)

BACKGROUND (continued)

2. closed by manual valves, blind flanges, or de-activated automatic valves secured in their closed positions, except as provided in LCO 3.6.3, "Containment Isolation Valves."

b. Each air lock is OPERABLE, except as provided in LCO 3.6.2, "Containment Air Locks."

APPLICABLE SAFETY ANALYSES

The safety design basis for the containment is that the containment must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate.

The DBAs that result in a release of radioactive material within containment are a loss of coolant accident, a main steam line break (MSLB), and a control element assembly ejection accident (Ref. 2). In the analysis of each of these accidents, it is assumed that containment is OPERABLE such that release of fission products to the environment is controlled by the rate of containment leakage. The containment was designed with an allowable leakage rate of 0.10% of containment air weight per day (Ref. 2). This leakage rate is defined in 10 CFR 50, Appendix J, Option B (Ref. 1), as L_a: the maximum allowable containment leakage rate at the calculated maximum peak containment internal pressure related to the design basis loss-of-coolant accident, P_a, at ~~45.0~~ 48.0 psig (Ref. 4). P_a will conservatively be assumed to be equal to the calculated peak containment internal pressure resulting from the design basis Main Steam Line Break, ~~56.5~~ 51.5 psig (Ref. 4), for the purpose of containment testing in accordance with this Technical Specification.

Satisfactory leakage rate test results are a requirement for the establishment of containment OPERABILITY.

The containment satisfies Criterion 3 of the NRC Policy Statement.

LCO

Containment OPERABILITY is maintained by limiting leakage to $\leq 1.0\ L_a$, except prior to the first startup after performing a required Containment Leakage Rate Testing Program leakage test. At this time, the applicable leakage limits must be met.

Compliance with this LCO will ensure a containment configuration, including equipment hatches, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analysis.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

For atmospheric containment, the DBAs that result in a release of radioactive material within containment are a loss of coolant accident (LOCA), a main steam line break (MSLB) and a control element assembly (CEA) ejection accident (Ref. 2). In the analysis of each of these accidents, it is assumed that containment is OPERABLE such that release of fission products to the environment is controlled by the rate of containment leakage. The containment was designed with an allowable leakage rate of 0.10% of containment air weight per day (Ref. 2). This leakage rate is defined in 10 CFR 50, Appendix J, Option B (Ref. 1), as L_a: the maximum allowable containment leakage rate at the calculated maximum peak containment internal pressure related to the design basis loss-of-coolant accident, P_a, at ~~45.9~~ 48.0 psig (Ref. 3). P_a will conservatively be assumed to be equal to the calculated peak containment internal pressure resulting from the design basis Main Steam Line Break, ~~56.5~~ 51.5 psig (Ref. 3), for the purpose of containment testing in accordance with this Technical Specification. This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air lock.

The containment air locks satisfy Criterion 3 of the NRC Policy Statement.

LCO

Each containment air lock forms part of the containment pressure boundary. As part of the containment pressure boundary, the air lock safety function is related to control of the containment leakage rate resulting from a DBA. Thus, each air lock's structural integrity and leak tightness are essential to the successful mitigation of such an event.

Each air lock is required to be OPERABLE. For the air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, and both air lock doors must be OPERABLE. The door seals and sealing surface are considered a part of the air lock. The interlock allows only one air lock door of an air lock to be opened at one time. This provision ensures that a gross breach of containment does not exist when containment is required to be OPERABLE. Closure of a single door in each air lock is sufficient to provide a leak tight barrier following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry into or exit from containment.

(continued)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4 Containment Pressure

BASES

BACKGROUND	The containment pressure is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a loss of coolant accident (LOCA) or main steam line break (MSLB). These limits also prevent the containment pressure from exceeding the containment design negative pressure differential with respect to the outside atmosphere in the event of inadvertent actuation of the Containment Spray System. Containment pressure is a process variable that is monitored and controlled. The containment pressure limits are derived from the input conditions used in the containment functional analyses and the containment structure external pressure analysis. Should operation occur outside these limits coincident with a Design Basis Accident (DBA), post accident containment pressures could exceed calculated values.
APPLICABLE SAFETY ANALYSES	Containment internal pressure is an initial condition used in the DBA analyses to establish the maximum peak containment internal pressure. The limiting DBAs considered for determining the maximum containment internal pressure (P_a) are the LOCA and MSLB. An MSLB at 3458 MWt power with a single failure of one main steam isolation valve (MSIV) to close results in the highest calculated internal containment pressure of ~~56.5~~ 51.5 psig, which is below the internal design pressure of 60 psig. The postulated DBAs are also analyzed assuming degraded containment Engineering Safety Feature (ESF) systems (i.e., assuming the loss of one ESF bus, or in the case of a LOCA, a failure of one diesel generator to start, resulting in one train of the Containment Spray System and one train of the Containment Cooling System being rendered inoperable). The ESF bus single failure is more limiting for the LOCA event but not for the MSLB event. It is the maximum containment pressure that is used to ensure that the licensing basis dose limitations are met (Reference 1). The initial pressure condition used in the containment analysis was the LCO limit of 1.5 psig plus 0.6 psig effective instrumentation total loop uncertainty. This resulted in a maximum peak pressure from an MSLB of ~~56.5~~ 51.5 psig.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

initial pre-accident temperature inside containment was assumed to be 120°F (Ref. 1).

The initial containment average air temperature condition of 120°F resulted in a maximum vapor temperature in containment of ~~409°F~~ 380°F, with a 75 second duration for the containment temperature exceeding 300°F. NUREG-0712 (NRC Safety Evaluation Report for SONGS 2&3, SER Supplement 2, Section 6.2.1) documents the approval of a maximum containment temperature of 405.6°F, with an 85 second duration for the containment temperature exceeding 300°F. The containment average air temperature limit of 120°F ensures that, in the event of an accident, the temperature of the containment steel liner and concrete structure do not exceed the maximum design temperature of 300°F for containment. The consequence of exceeding this design temperature may be the potential for degradation of the containment structure under accident loads.

Containment average air temperature satisfies Criterion 2 of the NRC Policy Statement.

LCO

During a DBA, with an initial containment average air temperature less than or equal to the LCO temperature limit, the resultant accident temperature profile assures that the containment structural temperature is maintained below its design temperature and that required safety related equipment will continue to perform its function.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining containment average air temperature within the limit is not required in MODE 5 or 6.

ACTIONS

A.1

When containment average air temperature is not within the limit of the LCO, it must be restored to within limit within 8 hours. This Required Action is necessary to return operation to within the bounds of the containment analysis. The 8 hour Completion Time is acceptable considering the sensitivity of the analysis to variations in this parameter and provides sufficient time to correct minor problems.

(continued)

BASES (continued)

BACKGROUND

Containment Spray System (continued)

operator in accordance with the emergency operating procedures.

Containment Cooling System

Two trains of containment cooling, each of sufficient capacity to supply 50% of the design cooling requirement, are provided. Two trains with two fan units each are supplied with cooling water from the Component Cooling Water System. All four fans are required to furnish the design cooling capacity. Air is drawn into the coolers through the fans and discharged to the steam generator compartments and pressurizer compartment.

In post accident operation following a containment cooling actuation signal (CCAS), all four Containment Cooling System fans are designed to start automatically. Cooling is from the Component Cooling Water (CCW) System. The temperature of the CCW System water is an important factor in the heat removal capability of the fan units.

APPLICABLE SAFETY ANALYSES

The Containment Spray System and Containment Cooling System limit the temperature and pressure that could be experienced following a DBA. The limiting DBAs considered relative to containment temperature and pressure are the loss of coolant accident (LOCA) and the main steam line break (MSLB). The DBA LOCA and MSLB are analyzed using computer codes designed to predict the resultant containment pressure and temperature transients. No DBAs are assumed to occur simultaneously or consecutively. The postulated DBAs are analyzed with regard to various single active failures of containment ESF systems, including the loss of one ESF bus, resulting in one train of the containment spray system and one train of the Containment Cooling System being rendered inoperable.

The analysis and evaluation show that under the worst case scenario, the highest peak containment pressure is ~~56.5~~ 51.5 psig (experienced during an MSLB with a single active failure of one main steam isolation valve (MSIV) to close). The analysis shows that ~~the peak containment vapor temperature is 409°F~~ 380°F, with a 75 second duration for the containment temperature exceeding 300°F (experienced during the same MSLB). NUREG-0712 (NRC Safety Evaluation Report for SONGS 2&3, SER Supplement 2, Section 6.2.1) documents the approval of a maximum containment temperature of 405.6°F, with an 85 second duration for the containment temperature exceeding 300°F.

(continued)

Attachment H

(Proposed LCS Pages)

SONGS Unit 2

(for information only)

LCS 3.6.100 Prestressed Concrete Containment Tendon Surveillance Program

BASES

This limitation ensures that the structural integrity of the Containment will be maintained comparable to the original design standards for the life of the facility. Structural integrity is required to ensure that the Containment will withstand the maximum pressure of ~~56.5~~ 51.5 psig in the event of a steam line break accident. The measurement of Containment tendon lift off force, the tensile tests of the tendon wires or strands, the visual examination of tendons, anchorages and exposed interior and exterior surfaces of the Containment, the chemical and visual examination of the sheathing filler grease, and the Type A leakage tests are sufficient to demonstrate this capability.

Containment structural integrity is demonstrated in accordance with the ISI program.

Attachment I

(Proposed Pages)

(With Changes from PCN-582 and PCN-583)

SONGS Unit 3

5.5.2.15 Containment Leakage Rate Testing Program

A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995 as modified by the following exception:

> NEI 94-01 - 1995, Section 9.2.3: The first Type A Test performed after the September 10, 1995 Type A Test shall be performed prior to startup from the Unit 3 Cycle 16 refueling outage, which is scheduled to commence in the fall of 2010 and to end in the first quarter of 2011. SONGS Unit 3 shall not operate past September 9, 2011 until the Type A Test is satisfactorily completed.

The calculated peak containment internal pressure related to the design basis loss-of-coolant accident, P_a, is 48.0 psig (P_a will conservatively be assumed to be equal to the calculated peak containment internal pressure for the design basis Main Steam Line Break (51.5 psig) for the purpose of containment testing in accordance with this Technical Specification).

The maximum allowable containment leakage rate, L_a, at P_a, shall be 0.10% of containment air weight per day.

Leakage rate acceptance criteria are:

a. The Containment overall leakage rate acceptance criterion is $\leq 1.0\ L_a$. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are $\leq 0.60\ L_a$ for the Type B and Type C tests and $\leq 0.75\ L_a$ for the Type A tests;

b. Air lock testing acceptance criteria are:

   1) Overall air lock leakage rate is $\leq 0.05\ L_a$ when tested at $\geq P_a$.

   2) For each door, the leakage rate is $\leq 0.01\ L_a$ when pressurized to ≥ 9.0 psig.

(continued)