UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

August 29, 2013

Mr. William G. Gideon, Vice President
H. B. Robinson Steam Electric Plant
Carolina Power & Light Company
3581 West Entrance Road
Hartsville, SC 29550

SUBJECT: H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2 - ISSUANCE OF AN AMENDMENT TO REVISE THE STEAM GENERATOR PROGRAM INSPECTION FREQUENCIES AND TUBE SAMPLE SELECTION AND APPLICATION OF PERMANENT ALTERNATE REPAIR CRITERIA (H*) (TAC NO. ME9448)

Dear Mr. Gideon:

The Nuclear Regulatory Commission has issued the enclosed Amendment No. 235 to Renewed Facility Operating License No. DPR-23 for the H. B. Robinson Steam Electric Plant, Unit No. 2 (HBRSEP). This amendment changes the HBRSEP Technical Specifications (TSs) in response to your application dated August 29, 2012 (Agencywide Documents Access and Management System Accession No. ML12251A363), as supplemented by letters dated, March 6, 2013 (ML13072A300), April 9, 2013 (ML13123A221), and August 22, 2013.

The license amendment combines two changes that affect the same TS sections into one license amendment. The first part proposes to implement revisions consistent with TS Task Force-510, Revision 2, "Revision to Steam Generator (SG) Program Inspection Frequencies and Tube Sample Selection." The second part revises TS 5.5.9 "Steam Generator Program" to exclude portions of the SG tube below the top of the SG tubesheet from periodic inspections by implementing the permanent alternate criteria "H*."

A copy of the related Safety Evaluation is enclosed. Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,

Siva P. Lingam

Siva P. Lingam, Project Manager
Plant Licensing Branch II-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-261

Enclosures:
1. Amendment No. 235 to DPR-23
2. Safety Evaluation

cc w/enclosures: Distribution via ListServ

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

CAROLINA POWER & LIGHT COMPANY

DOCKET NO. 50-261

H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 235
Renewed License No. DPR-23

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by Carolina Power & Light Company (the licensee), dated August 29, 2012, as supplemented by letters dated March 6, 2013, April 9, 2013, and August 22, 2013, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications, as indicated in the attachment to this license amendment; and paragraph 3.B. of Renewed Facility Operating License No. DPR-23 is hereby amended to read as follows:

B. Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 235 are hereby incorporated in the license.

The licensee shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of the date of its issuance and shall be implemented within 30 days.

FOR THE NUCLEAR REGULATORY COMMISSION

Douglas A. Broaddus, Acting Chief
Plant Licensing Branch II-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment:
Changes to Operating License No. DPR-23
and the Technical Specifications

Date of Issuance: August 29, 2013

ATTACHMENT TO LICENSE AMENDMENT NO. 235

RENEWED FACILITY OPERATING LICENSE NO. DPR-23

DOCKET NO. 50-261

Replace the following pages of the Renewed Facility Operating License and Appendix "A" Technical Specifications with the enclosed pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Remove	Insert
License DPR-23	License DPR-23
Page 3	Page 3
TSs	TSs
5.0-12	5.0-12
5.0-13	5.0-13
5.0-14	5.0-14
5.0-28	5.0-28
3.4-52	3.4-52
3.4-53	3.4-53

neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

D. Pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess, and use in amounts as required any byproduct, source, or special nuclear material without restriction to chemical or physical form for sample analysis or instrument and equipment calibration or associated with radioactive apparatus or components;

E. Pursuant to the Act and 10 CFR Parts 30 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by operation of the facility.

3. This renewed license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations: 10 CFR Part 20, Section 30.34 of 10 CFR Part 30, Section 40.41 of 10 CFR Part 40, Section 50.54 and 50.59 of 10 CFR Part 50, and Section 70.32 of 10 CFR Part 70; and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

A. Maximum Power Level

The licensee is authorized to operate the facility at a steady state reactor core power level not in excess of 2339 megawatts thermal.

B. Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. 235 are hereby incorporated in the license.

The licensee shall operate the facility in accordance with the Technical Specifications.

(1) For Surveillance Requirements (SRs) that are new in Amendment 176 to Final Operating License DPR-23, the first performance is due at the end of the first surveillance interval that begins at implementation of Amendment 176. For SRs that existed prior to Amendment 176, including SRs with modified acceptance criteria and SRs whose frequency of performance is being extended, the first performance is due at the end of the first surveillance interval that begins on the date the Surveillance was last performed prior to implementation of Amendment 176.

5.5.9 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:

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.

b. Performance criteria for SG tube integrity. SG tube integrity shall be maintained by meeting the performance criteria for tube structural integrity, accident induced leakage, and operational LEAKAGE.

   1. Structural integrity performance criterion: All in-service steam generator tubes shall retain structural integrity over the full range of normal operating conditions (including startup, operation in the power range, hot standby, and cool down), all anticipated transients included in the design specification, and design basis accidents. This includes retaining a safety factor of 3.0 against burst under normal steady state full power operation primary-to-secondary pressure differential and a safety factor of 1.4 against burst applied to the design basis accident primary-to-secondary pressure differentials. Apart from the above requirements, additional loading conditions associated with the design basis accidents, or combination of accidents in accordance with the design and licensing basis, shall also be evaluated to determine if the associated loads contribute significantly to burst or collapse. In the assessment of tube integrity, those loads that do significantly affect burst or collapse shall be determined and assessed in combination with the loads due to pressure with a safety factor of 1.2 on the combined primary loads and 1.0 on axial secondary loads.

   2. Accident induced leakage performance criterion: The primary to secondary accident induced leakage rate for any design basis accident, other than a SG tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all SGs and leakage rate for an individual SG. Leakage is not to exceed 75 gallons per day per SG.

   3. The operational LEAKAGE performance criterion is specified in LCO 3.4.13, "RCS Operational LEAKAGE."

(continued)

5.5.9 Steam Generator (SG) Program
(continued)

c. Provisions for SG tube plugging criteria. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding the following criteria shall be plugged: 47% of the nominal tube wall thickness if the next inspection interval of that tube is ≤ 12 months, and a 2% reduction in the plugging criteria for each 12 month period until the next inspection of the tube.

   The following alternate tube plugging criteria shall be applied as an alternative to the preceding criteria:

   Tubes with service-induced flaws located greater than 18.11 inches below the top of the tubesheet do not require plugging. Tubes with service-induced flaws located in the portion of the tube from the top of the tubesheet to 18.11 inches below the top of the tubesheet shall be plugged upon detection.

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 plugging 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. A degradation assessment 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 installation.

   2. After the first refueling outage following SG installation, inspect each SG at least every 48 effective full power months or at least every other refueling outage (whichever results in more frequent inspections). In addition, the minimum number of tubes inspected at each scheduled inspection shall be the number of tubes in all SGs divided by the number of SG inspection outages scheduled in each inspection period as defined in a, b, and c below. If a degradation assessment indicates the potential for a type of degradation to occur at a location not previously inspected with a technique capable of detecting this type of degradation at this location and that may satisfy

(continued)

5.5.9 Steam Generator (SG) Program
(continued)

the applicable tube plugging criteria, the minimum number of locations inspected with such a capable inspection technique during the remainder of the inspection period may be prorated. The fraction of locations to be inspected for this potential type of degradation at this location at the end of the inspection period shall be no less than the ratio of the number of times the SG is scheduled to be inspected in the inspection period after the determination that a new form of degradation could potentially be occurring at this location divided by the total number of times the SG is scheduled to be inspected in the inspection period. Each inspection period defined below may be extended up to 3 effective full power months to include a SG inspection outage in an inspection period and the subsequent inspection period begins at the conclusion of the included SG inspection outage.

a) After the first refueling outage following SG installation, inspect 100% of the tubes during the next 120 effective full power months. This constitutes the first inspection period;

b) During the next 96 effective full power months, inspect 100% of the tubes. This constitutes the second inspection period; and

c) During the remaining life of the SGs, inspect 100% of the tubes every 72 effective full power months. This constitutes the third and subsequent inspection periods.

3. If crack indications are found in any portion a SG tube not excluded above, then the next inspection for each affected and potentially affected SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever results in more frequent inspections). 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.

5.5.10 Secondary Water Chemistry Program

This program provides controls for monitoring secondary water chemistry to inhibit SG tube degradation. The program shall include:

a. Identification of critical parameters, their sampling frequency, sampling points, and control band limits;

(continued)

5.6 Reporting Requirements (continued)

5.6.7 Tendon Surveillance Report

a. Notification of a pending sample tendon test, along with detailed acceptance criteria, shall be submitted to the NRC at least two months prior to the actual test.

b. A report containing the sample tendon test evaluation shall be submitted to the NRC within six months of conducting the test.

5.6.8 Steam Generator Tube Inspection Report

A report shall be submitted within 180 days after the initial entry into MODE 4 following completion of an inspection performed in accordance with the Specification 5.5.9, Steam Generator (SG) Program. The report shall include:

a. The scope of inspections performed on each SG.

b. Degradation mechanisms found.

c. Nondestructive examination techniques utilized for each degradation mechanism.

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

e. Number of tubes plugged during the inspection outage for each degradation mechanism.

f. The number and percentage of tubes plugged to date, and the effective plugging percentage in each steam generator.

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

h. The primary to secondary leakage rate observed in each SG (if it is not practical to assign the leakage to an individual SG, the entire primary to secondary leakage should be conservatively assumed to be from one SG) during the cycle preceding the inspection that is the subject of the report.

i. The calculated accident induced leakage rate from the portion of the tubes below 18.11 inches from the top of the tubesheet for the most limiting accident in the most limiting SG. In addition, if the calculated accident induced leakage rate from the most limiting accident is less than 1.87 times the maximum operational primary to secondary leakage rate, the report should describe how it was determined, and

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.18 Steam Generator (SG) Tube Integrity

LCO 3.4.18 SG tube integrity shall be maintained.

AND

All SG tubes satisfying the tube plugging 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 plugging 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. OR SG tube integrity not maintained.	B.1	Be in MODE 3.	6 hours
	AND		
	B.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIERMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.18.1	Verify SG tube integrity in accordance with the Steam Generator Program.	In accordance with the Steam Generator Program
SR 3.4.18.2	Verify that each inspected SG tube that satisfies the tube plugging criteria is plugged in accordance with the Steam Generator Program.	Prior to entering MODE 4 following a SG tube inspection

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SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 235 TO

RENEWED FACILITY OPERATING LICENSE NO. DPR-23

CAROLINA POWER AND LIGHT COMPANY

H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT 2

DOCKET NO. 50-261

1.0 INTRODUCTION

By letter to the U.S. Nuclear Regulatory Commission (NRC) dated August 29, 2012 (Reference 1), as supplemented by letters dated March 6, 2013 (Reference 2), and April 9, 2013 (Reference 3), and August 22, 2013 (Reference 25), Carolina Power and Light Company (the licensee), doing business as Duke Energy, submitted a license amendment request (LAR) for changes to the Technical Specifications (TSs) for H. B. Robinson Steam Electric Plant Unit No. 2 (HBRSEP). The request proposed changes to TS 5.5.9, "Steam Generator (SG) Program," and TS 5.6.8, "Steam Generator Tube Inspection Report" in order to implement the H* (H-star) alternate repair criteria on a permanent basis. The request also proposed changes to TS 3.4.18, "Steam Generator (SG) Tube Integrity," TS 5.5.9 "Steam Generator (SG) Program," and TS 5.6.8 "Steam Generator Tube Inspection Report," to adopt the program improvements in the Technical Specification Task Force Traveler (TSTF)-510, Revision 2, "Revision to Steam Generator Program Inspection Frequencies and Tube Sample Selection."

The supplement letters dated March 6, 2013, April 9, 2013, and August 22, 2013, provided additional information that clarified the application, did not expand the scope of the application as originally noticed, and did not change the staff's initial proposed no significant hazards consideration determination as published in the *Federal Register* on October 16, 2012 (77 FR 63348).

2.0 BACKGROUND

HBRSEP has three Model 44F replacement SGs, which were designed and fabricated by Westinghouse. There are 3,214 thermally treated Alloy 600 (Alloy 600TT) tubes with a nominal outside diameter of 0.875 inches and a nominal wall thickness of 0.050 inches. The thermally treated tubes are hydraulically expanded for the full depth of the 21-inch thick tubesheet and are welded to the tubesheet at each tube end. Until the fall of 2004, no instances of stress corrosion cracking affecting the tubesheet region of Alloy 600TT tubing had been reported at any nuclear power plant in the United States.

In the fall of 2004, crack-like indications were found in tubes in the tubesheet region of Catawba Unit 2. These crack-like indications were found in a tube overexpansion (OXP) that was approximately 7 inches below the top of the tubesheet (hot leg side) in one tube, and just above the tube-to-tubesheet weld in a region of the tube known as the tack expansion region in several other tubes. Indications were also reported near the tube-to-tubesheet welds, which join the tube to the tubesheet. An OXP is created when the tube is expanded into a tubesheet bore hole that is not perfectly round. These out-of-round conditions were created during the tubesheet drilling process by conditions such as drill bit wandering or chip gouging. The tack expansion is an approximately 1-inch long expansion at each tube end. The purpose of the tack expansion is to facilitate performing the tube-to-tubesheet weld, which is made prior to the hydraulic expansion of the tube over the full tubesheet depth.

Since the initial findings at Catawba Nuclear Station Unit 2 in the fall of 2004, other nuclear plants with Alloy 600TT tubing have found crack-like indications in tubes within the tubesheet as well. Most of the indications were found in the tack expansion region near the tube-end welds and were a mixture of axial and circumferential primary water stress-corrosion cracking.

Over time, these cracks can be expected to become more and more extensive, necessitating more extensive inspections of the lower tubesheet region and more extensive tube plugging or repairs, with attendant increased cost and the potential for shortening the useful lifetime of the SGs. To avoid these impacts, the affected licensees and their contractor, Westinghouse Electric Company, LLC, have developed proposed alternative inspection and repair criteria applicable to the tubes in the lowermost region of the tubesheets. These criteria are referred to as the "H*" criteria. H* is the minimum engagement distance between the tube and tubesheet, measured downward from the top of the tubesheet, that is proposed as needed to ensure the structural and leakage integrity of the tube-to-tubesheet joints. The proposed H* alternate repair criteria would exclude the portions of tubing below the H* distance from inspection and plugging requirements, on the basis that flaws below the H* distance are not detrimental to the structural and leakage integrity of the tube-to-tubesheet joints.

Requests for permanent H* amendments were proposed for a number of plants as early as 2005. The NRC staff identified a number of issues with these early proposals and in subsequent proposals made in 2009, and was unable to approve H* amendments on a permanent basis pending resolution of these issues. The NRC staff found it did have a sufficient basis to approve H* amendments on an interim (temporary) basis, based on the relatively limited extent of cracking existing in the lower tubesheet region at the time the interim amendments were approved. The technical basis for approving the interim amendments is provided in detail in the NRC staff's safety evaluations accompanying issuance of these amendments.

License amendment No. 214 (Reference 4) was issued in April 2007 and modified TS 5.5.9, "Steam Generator (SG) Program," and TS 5.6.8, "Steam Generator Tube Inspection Report," by incorporating interim alternate repair criteria and associated tube inspection and reporting requirements. License amendment 224 (Reference 5) was approved in May 2010 and incorporated interim alternate repair criteria for an additional operating cycle. The proposed permanent amendments are similar to these interim amendments, with the exception that the proposed H* distance would be increased slightly (to 18.11 inches) compared to the value in the second interim amendment (17.28 inches). The NRC staff recently approved similar permanent H* amendments for Turkey Point Nuclear Generating Station Units 3 and 4 (Reference 6).

In the LAR, the licensee has also proposed to adopt the changes specified in TSTF-510, Revision 2. The changes in TSTF-510, Revision 2, reflect industry licensees' early implementation experience with their current TSs. The changes in TSTF-510, Revision 2, are editorial corrections, changes, and clarifications intended to improve internal consistency, consistency with implementing industry documents, and usability, without changing the intent of the requirements. The proposed changes are an improvement to the existing SG inspection requirements and continue to provide assurance that the plant licensing basis will be maintained between SG inspections. The NRC staff approved TSTF-510, Revision 2 for use with the consolidated line item process on October 19, 2011 (Reference 7). Because this amendment does more than just implement TSTF-510, the licensee could not use the consolidated line item process.

3.0 REGULATORY EVALUATION

The SG tubes are part of the reactor coolant pressure boundary (RCPB) and isolate fission products in the primary coolant from the secondary coolant and the environment. For the purposes of this safety evaluation, SG tube integrity means that the tubes are capable of performing this safety function in accordance with the plant design and licensing basis.

The General Design Criteria (GDC) in Appendix A to Title 10 of the Code of *Federal Regulations* (10 CFR), Part 50 provide regulatory requirements in the GDC, which state that the RCPB shall have "an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture" (GDC 14), "shall be designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences" (GDC 15 and 31), shall be of "the highest quality standards practical" (GDC 30), and shall be designed to permit "periodic inspection and testing...to assess... structural and leaktight integrity" (GDC 32). HBRSEP received a construction permit prior to May 21, 1971, which is the date the GDC in Appendix A of 10 CFR Part 50 became effective. Although the plant is exempt from the current GDC, the licensee states it is in compliance with the 1967 GDC that were in effect when HBRSEP was licensed, and discusses how HBRSEP meets each of these GDC in Sections 3.1.1 and 3.1.2 of the Updated Final Safety Analysis Report (UFSAR). A review of the 1967 GDC shows that the GDC applicable to the RCPB and SGs are comparable to the requirements of the current GDC.

Section 50.55a to 10 CFR specifies that components that are part of the RCPB must meet the requirements for Class 1 components in Section III of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), except as provided in 10 CFR 50.55a(c)(2), (3), and (4). Section 50.55a(g)(4) further requires that throughout the service life of pressurized-water reactor (PWR) facilities like HBRSEP, ASME Code Class 1 components meet the Section XI requirements of the ASME Code to the extent practical, except for design and access provisions, and pre-service examination requirements. This requirement includes the inspection and repair criteria of Section XI of the ASME Code. The ASME Code Section XI requirements pertaining to in-service inspection of SG tubing are augmented by additional requirements in the TSs.

Section 182(a) of the Atomic Energy Act requires nuclear power plant operating licenses to include TSs as part of any license. The NRC regulatory requirements related to the content of the TSs are contained in 10 CFR 50.36, "Technical Specifications." The TS requirements in

10 CFR 50.36 include the following categories: 1) safety limits, limiting safety systems settings and limited control settings; 2) limiting conditions for operation; 3) surveillance requirements; 4) design features; 5) administrative controls; 6) decommissioning; 7) initial notification; and 8) written reports.

The regulation at 10 CFR 50.36(c)(5) defines administrative controls as "the provisions relating to organization and management, procedures, recordkeeping, review and audit, and reporting necessary to assure the operation of the facility in a safe manner." Programs established by the licensee, including the SG program, are listed in the administrative controls section of the TSs to operate the facility in a safe manner. For HBRSEP, the requirements for performing SG tube inspections and repair are in TS 5.5.9, while the requirements for reporting the SG tube inspections and repair are in TS 5.6.8.

The TSs for all PWR plants require that a SG program be established and implemented to ensure that SG tube integrity is maintained. For HBRSEP, SG tube integrity is maintained by meeting the performance criteria specified in TS 5.5.9.b for structural and leakage integrity, consistent with the plant design and licensing basis. TS 5.5.9.a requires that a condition monitoring assessment be performed during each outage in which the SG tubes are inspected, to confirm that the performance criteria are being met. TS 5.5.9.d includes provisions regarding the scope, frequency, and methods of SG tube inspections. These provisions require that the inspections be performed with the objective of detecting flaws of any type that may be present along the length of a tube and that may satisfy the applicable tube repair criteria. The applicable tube repair criteria, specified in TS 5.5.9.c, are that tubes found during inservice inspection to contain flaws with a depth equal to or exceeding 40 percent of the nominal wall thickness shall be plugged, unless the tubes are permitted to remain in service through application of alternate plugging criteria provided in TS 5.5.9.c, such as is being proposed for HBRSEP. The staff reviewed the proposed alternate plugging criteria and has determined that the alternate plugging criteria does not impact the integrity of the SG tubes and, therefore, the SG tubes still meet the design requirements and the requirements for Class 1 components in Section III of the ASME Code.

HBRSEP TS 3.4.13 also includes a limit on operational primary-to-secondary leakage (75 gallons per day), beyond which the plant must be promptly shut down. Should a flaw exceeding the tube plugging limit not be detected during the periodic tube surveillance required by the plant TSs, the operational leakage limit provides added assurance of timely plant shutdown before tube structural and leakage integrity, consistent with the design and licensing bases, are impaired.

As part of the plant's licensing bases, applicants for PWR licenses are required to analyze the consequences of postulated design-basis accidents (DBAs), such as a SG tube rupture and a main steam line break (MSLB). These analyses consider primary-to-secondary leakage that may occur during these events and must show that the offsite radiological consequences do not exceed the applicable limits of 10 CFR 50.67 or 10 CFR Part 100 for offsite doses, GDC 19 for control room operator doses (or some fraction thereof as appropriate to the accident), or the NRC-approved licensing basis (e.g., a small fraction of these limits). No accident analyses for HBRSEP are being changed because of the proposed amendment and, thus, no radiological consequences of any accident analysis are being changed. The proposed changes maintain the accident analyses and consequences that the NRC has reviewed and approved for the postulated DBAs for SG tubes.

4.0 TECHNICAL EVALUATION

4.1 Proposed Changes to the TS

The current TSs are shown below with the proposed changes, including the currently approved interim alternate plugging criteria and associated tube inspection and reporting requirements.

4.1.1 TS 5.5.9: "Steam Generator (SG) Program"

The last sentence of the introductory paragraph in TS 5.5.9 currently states: "In addition, the Steam Generator Program shall include the following provisions:"

Proposed Change: The change would delete the word "provisions" such that the sentence would state: "In addition, the Steam Generator Program shall include the following:" TS 5.5.9 would be revised, consistent with TSTF-510, to delete the duplicative word "provisions."

The basis for this change is that subsequent paragraphs in TS 5.5.9 start with "Provisions for..." and the word "provisions" in the introductory paragraph is duplicative.

Assessment: The NRC staff has reviewed TS 5.5.9 and agrees that the word, "provisions," in the introductory paragraph is duplicative. The NRC staff agrees that the change is editorial in nature, and therefore is acceptable.

4.1.2 TS 5.5.9.b.1, "Structural Integrity Performance Criterion"

The first sentence currently states:

> "All in-service steam generator tubes shall retain structural integrity over the full range of normal operating conditions (including startup, operation in the power range, hot standby, and cool down, all anticipated transients included in the design specification), and design basis accidents."

Proposed Change: Revise the sentence as follows, consistent with TSTF-510, to correct the misplaced closing parenthesis.

> "All in-service steam generator tubes shall retain structural integrity over the full range of normal operating conditions (including startup, operation in the power range, hot standby, and cool down), all anticipated transients included in the design specification, and design basis accidents."

The basis for the change is that this sentence inappropriately includes anticipated transients in the description of normal operating conditions.

Assessment: The NRC staff agrees the current wording is incorrect and that anticipated transients should be differentiated from normal operating conditions. Therefore, the NRC staff finds the change acceptable.

4.1.3 TS 5.5.9.c, "Provisions for SG tube repair criteria"

TS 5.5.9.c currently states:

> Provisions for SG tube repair criteria. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding the following criteria shall be plugged: 47% of the nominal tube wall thickness if the next inspection interval of that tube is 12 months, and a 2% reduction in the repair criteria for each 12 month period until the next inspection of the tube.
>
> The following alternate tube repair criteria shall be applied as an alternative to the preceding criteria, until the end of Operating Cycle 27:
>
> Tubes with service-induced flaws located greater than 17.28 inches below the top of the tubesheet do not require plugging. Tubes with service-induced flaws located in the portion of the tube from the top of the tubesheet to 17.28 inches below the top of the tubesheet shall be plugged upon detection.

Proposed Change: Revise the sentence as follows, consistent with TSTF-510:

> Provisions for SG tube plugging criteria. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding the following criteria shall be plugged: 47% of the nominal tube wall thickness if the next inspection interval of that tube is 12 months, and a 2% reduction in the plugging criteria for each 12-month period until the next inspection of the tube.
>
> The following alternate tube plugging criteria shall be applied as an alternative to the preceding criteria:
>
> Tubes with service-induced flaws located greater than 18.11 inches below the top of the tubesheet do not require plugging. Tubes with service-induced flaws located in the portion of the tube from the top of the tubesheet to 18.11 inches below the top of the tubesheet shall be plugged upon detection.

TS 5.5.9.c would be revised, consistent with TSTF-510, to change "tube repair criteria" to "tube plugging [or repair] criteria." As HBRSEP does not have an approved SG repair technique the bracketed references to repair are deleted. Also, the expiration of the applicability of the alternate repair criteria at the end of Operating Cycle 27 is deleted and the value of H* is revised consistent with application of the H* methodology to HBRSEP on a permanent basis.

Assessment: The NRC staff finds that the proposed change provides a more accurate label of the criteria and, therefore, adds clarity to the specification. This is because one of two actions must be taken when the criteria are exceeded. One action is to remove the tube from service by plugging the tube at both tube ends. The alternative action is to repair the tube, but only if such a repair is permitted by 5.5.9.c of TS. Therefore, the NRC staff finds the change acceptable. The proposed change in the value of H* is discussed in Section 4.2.

4.1.4 TS 5.5.9.d, "Provisions for SG tube inspections"

The first paragraph of TS 5.5.9.d currently states:

> 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 (until the end of Operating Cycle 27 the required inspection length extends 17.28 inches below the top of the tubesheet on the tube hot leg side to 17.28 inches below the top of the tubesheet on the tube cold leg side), 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.

Proposed Change:

> 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 18.11 inches below the top of the tubesheet on the hot leg to 18.11 inches below the top of the tubesheet on the cold leg), and that may satisfy the applicable tube plugging 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. A degradation assessment 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.

TS 5.5.9.d would be revised, consistent with TSTF-510, to change "repair" to "plugging" and "assessment of degradation" to "degradation assessment." With implementation of the alternate repair criteria on a permanent basis, the portion of the tube from the tube-to-tubesheet weld to the H* distance below the top of the tubesheet does not satisfy the alternate repair/plugging criteria (see specification 5.5.9.c above) and is not included in the required inspection. Therefore, the description of the length of the steam generator tube subject to inspection in the third sentence is revised accordingly.

Assessment: The NRC staff finds that the proposed change from the term "assessment of degradation" to "degradation assessment" to be consistent with the terminology used in TSTF-510. The NRC staff agrees that the terminology should be consistent and finds the change acceptable. The proposed change from "repair" to "plugging" is discussed in Section 4.1.3. The proposed change in the value of H* is discussed in Section 4.2.

4.1.5 TS 5.5.9.d.1

TS 5.5.9.d.1 currently states:

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

Proposed Change:

> Inspect 100% of the tubes in each SG during the first refueling outage following SG installation.

TS 5.5.9.d.1 would be revised, consistent with TSTF-510, to change "replacement" to "installation."

Assessment: The NRC staff finds that the proposed change from the term "replacement" to "installation" to be consistent with the terminology used in TSTF-510. The NRC staff agrees that the terminology should be consistent and finds the change acceptable.

4.1.6 Paragraph 5.5.9.d for plants with SGs with Alloy 600TT

The paragraph currently states:

> Inspect 100% of the tubes at sequential periods of 120, 90, 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 48 effective full power months or two refueling outages (whichever is less) without being inspected.

Proposed Change:

> After the first refueling outage following SG installation, inspect each SG at least every 48 effective full power months or at least every other refueling outage (whichever results in more frequent inspections). In addition, the minimum number of tubes inspected at each scheduled inspection shall be the number of tubes in all SGs divided by the number of SG inspection outages scheduled in each inspection period as defined in a, b, and c below. If a degradation assessment indicates the potential for a type of degradation to occur at a location not previously inspected with a technique capable of detecting this type of degradation at this location and that may satisfy the applicable tube plugging criteria, the minimum number of locations inspected with such a capable inspection technique during the remainder of the inspection period may be prorated. The fraction of locations to be inspected for type of this potential degradation at this location at the end of the inspection period shall be no less than the ratio of the number

of times the SG is scheduled to be inspected in the inspection period after the determination that a new form of degradation could potentially be occurring at this location divided by the total number of times the SG is scheduled to be inspected in the inspection period. Each inspection period defined below may be extended up to 3 effective full power months to include a SG inspection outage in an inspection period and the subsequent inspection period begins at the conclusion of the included SG inspection outage.

a) After the first refueling outage following SG installation, inspect 100% of the tubes during the next 120 effective full power months. This constitutes the first inspection period.

b) During the next 96 effective full power months, inspect 100% of the tubes. This constitutes the second inspection period.

c) During the remaining life of the SGs, inspect 100% of the tubes every 72 effective full power months. This constitutes the third and subsequent inspection periods.

TS 5.5.9.d.2 would be revised, consistent with TSTF-510, to reflect the HBRSEP SGs with Alloy 600TT tubing, except the TSTF-510 content is modified slightly to incorporate the correction to the administrative error noted in the TSTF-510 letter dated March 28, 2012 (Reference 8). The correction in this letter notes that the phrase "tube repair criteria" should have read "tube plugging [or repair] criteria," consistent with other changes to TS 5.5.9.d of TSTF-510. The corrected phrase is modified to "tube plugging criteria" to reflect that HBRSEP does not have an approved SG tube repair method.

Assessment: Paragraph 5.5.9.d.2 in its current form and with the proposed changes is similar for each of the tube alloy types, but with differences that reflect the improved resistance of Alloy 600TT to stress corrosion cracking relative to Alloy 600MA and the improved resistance of Alloy 690TT relative to both Alloy 600MA and Alloy 600TT. These differences include progressively larger maximum inspection interval requirements and sequential inspection periods (during which 100% of the tubes must be inspected) for Alloy 600MA, 600TT, and Alloy 69 TT tubes, respectively. In addition, because of the longer maximum inspection intervals allowed for Alloy 600TT and 690TT tubes, paragraph 5.5.9.d.2 includes a restriction on the distribution of sampling over each sequential inspection period for Alloy 600TT and 690TT tubes that is not included for Alloy 600MA tubes.

The licensee proposes to move the first two sentences of paragraph 5.5.9.d.2 to the end of the paragraph and make editorial changes to improve clarity. The NRC staff finds these changes to be of a clarifying nature, not changing the current intent of these two sentences. However, the LAR also includes two changes to when inspections are performed as follows:

- The second inspection period would be revised from 90 to 96 effective full-power months (EFPMs).

- The third and subsequent inspection periods would be revised from 60 to 72 EFPMs.

The licensee characterizes these changes as marginal increases for consistency with typical fuel cycle lengths that better accommodate the scheduling of inspections. The NRC staff notes that plants with Alloy 600TT SG tubes typically inspect at 18- or 36-month intervals (one or two fuel cycles, respectively) depending on whether stress corrosion crack activity was observed during the most recent inspection. With these intervals, the last scheduled inspection during the first inspection period would occur at 108 months after the first refueling outage following SG installation. This is 12 months before the end of the first 120-EFPM inspection period. However, with the proposed changes to the length of the second and subsequent inspection periods, the NRC staff finds that the last scheduled inspections in the second and subsequent inspection periods will coincide exactly with the end of these periods.

The proposed changes would generally increase the number of inspections in each of the second and subsequent inspection periods by up to one additional inspection. This could reduce the required average minimum sample size during these periods. However, inspection sample sizes will continue to be subject to paragraph 5.5.9.d that states that in addition to meeting the requirements of paragraphs 5.5.9.d.1, d.2, and d.3, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure SG tube integrity is maintained until the next scheduled inspection. Therefore, the NRC staff concludes that with the proposed changes to the length of the second and subsequent inspection periods, compliance with the SG program requirements in TS 5.5.9 will continue to ensure both adequate inspection scopes and tube integrity.

For each inspection period, paragraph 5.5.9.d.2 currently requires that at least 50 percent of the tubes be inspected by the refueling outage nearest to the mid-point of the inspection period and the remaining 50 percent by the refueling outage nearest the end of the inspection period. The NRC staff notes that if there are not an equal number of inspections in the first half and second half of the inspection period, the average minimum sampling requirement may be markedly different for inspections in the first half of the inspection period compared to those in the second half, even when there are uniform intervals between each inspection. For example, a plant in the first (120 EFPM) inspection period with a scheduled 36-month interval (two fuel cycles) between each inspection would currently be required to inspect 50 percent of the tubes by the refueling outage nearest the midpoint of the inspection, which would be the third refueling outage in the period, 6 months before the mid-point. However, since no inspection is scheduled for that outage, the full 50-percent sample must be performed during the inspection scheduled for the second refueling outage in the period.

Two inspections would be scheduled to occur in the second half of the inspection period, at 72 and 108 months into the inspection period. Thus, the current sampling requirement could be satisfied by performing a 25-percent sample during each of these inspections or other combinations of sampling (e.g., 10 percent during one and 40 percent in the other) totaling 50 percent. The NRC staff finds there is no basis to require the minimum initial sample size to vary so much from inspection to inspection. The licensee proposes to revise this requirement such that the minimum sample size for a given inspection in a given inspection period is 100 percent divided by the number of scheduled inspections during that inspection period. For the above example, the proposed change would result in a uniform initial minimum sample size of 33.3 percent for each of the three scheduled inspections during the inspection period. The NRC staff concludes this proposed revision to be an improvement to the existing requirement since it provides a more consistent minimum initial sampling requirement.

The proposed changes to paragraph 5.5.9.d.2 include two new sentences addressing the prorating of required tube sample sizes if a degradation assessment indicates the potential for a type of degradation to occur at a location not previously inspected with a technique capable of detecting this type of degradation at this location and that may satisfy the applicable tube plugging criteria. For example, new information from another similar plant becomes available indicating the potential for circumferential cracking at a specific location on the tube. Previous degradation assessments had not identified the potential for this type of degradation at this location. Thus, previous inspections of this location had not been performed with a technique capable of detecting circumferential cracks. However, now that the potential for circumferential cracking has been identified at this location, paragraph 5.5.9.d requires a method of inspection to be performed with the objective of detecting circumferential cracks that may be present at this location and that may satisfy the applicable tube plugging criteria. Suppose this inspection is performed for the first time during the third of four SG inspections scheduled for one of the inspection periods. Paragraph 5.5.9.d.2 currently does not specify whether this location needs to be 100 percent inspected by the end of the inspection period, or whether a prorated approach may be taken. The NRC staff addressed this question in Issue 1 of NRC Regulatory Information Summary (RIS) 2009-04, "Steam Generator Tube Inspection Requirements," dated April 3, 2009 (ADAMS No. ML083470557), as follows:

> Issue 1: *A licensee may identify a new potential degradation mechanism after the first inspection in a sequential period. If this occurs, what are the expectations concerning the scope of examinations for this new potential degradation mechanism for the remainder of the period (e.g., do 100 percent of the tubes have to be inspected by the end of the period or can the sample be prorated for the remaining part of the period)?*
>
> [NRC Staff Position:] The TS contain requirements that are a mixture of prescriptive and performance-based elements. Paragraph "d" of these requirements indicates that the inspection scope, inspection methods, and inspection intervals shall be sufficient to ensure that SG tube integrity is maintained until the next SG inspection. Paragraph "d" is a performance-based element because it describes the goal of the inspections but does not specify how to achieve the goal. However, paragraph "d.2" is a prescriptive element because it specifies that the licensee must inspect 100 percent of the tubes at specified periods.
>
> If an assessment of degradation performed after the first inspection in a sequential period results in a licensee concluding that a new degradation mechanism (not anticipated during the prior inspections in that period) may potentially occur, the scope of inspections in the remaining portion of the period should be sufficient to ensure SG tube integrity for the period between inspections.
>
> In addition, to satisfy the prescriptive requirements of paragraph "d.2" that the licensee must inspect 100 percent of the tubes within a specified period, a prorated sample for the remaining portion of the period is appropriate for this potentially new degradation mechanism. This prorated sample should be such that if the licensee had implemented it at the beginning of the period, the TS

> requirement for the 100 percent inspection in the entire period (for this degradation mechanism) would have been met. A prorated sample is appropriate because (1) the licensee would have performed the prior inspections in this sequential period consistently with the requirements, and (2) the scope of inspections must be sufficient to ensure that the licensee maintains SG tube integrity for the period between inspections.

The NRC staff finds that proposed Sentences 3 and 4 clarify the existing requirement consistent with the NRC staff's position from RIS 2009-04 quoted above and are, therefore, acceptable.

The proposed fifth sentence in paragraph 5.5.9.d.2 states, "Each inspection period defined below may be extended up to 3 effective full power months to include a SG inspection outage in an inspection period and the subsequent inspection period begins at the conclusion of the included SG inspection outage." Allowing extension of the inspection periods by up to an additional 3 EFPMs potentially impacts the average tube inspection sample size to be implemented during a given inspection in that period. For example, if three SG inspections are scheduled to occur within the nominal 60-EFPM period, the minimum sample size for each of the three inspections could average as little as 33.3 percent of the tube population. If a fourth inspection can be included within the period by extending the period by 3 EFPMs, then the minimum sample size for each of the four inspections could average as little as 25 percent of the tube population. Since the subsequent period begins at the end of the included SG inspection outage, the proposed change does not impact the required frequency of SG inspection.

Required tube inspection sample sizes are also subject to the performance-based requirement in paragraph 5.5.9.d, which states, in part, that in addition to meeting the requirements of paragraphs 5.5.9.d.1, d.2, and d.3, "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." This requirement remains unchanged under the proposal. The NRC staff concludes the proposed fifth sentence, by allowing the potential for smaller sample sizes, involves only a relatively minor relaxation to the existing sampling requirements in paragraph 5.5.9.d.2. However, the performance-based requirements in 5.5.9.d ensure that adequate inspection sampling will be performed to ensure tube integrity is maintained. Thus, the NRC staff concludes that the proposed change is acceptable.

Finally, the first sentence of the proposed revision to paragraph 5.5.9.d.2 replaces the last sentence of the current paragraph 5.5.9.d.2. This sentence establishes the minimum allowable SG inspection frequency as at least every 48 EFPMs or at least every other refueling outage (whichever results in more frequent inspections). This minimum inspection frequency is unchanged from the current sentence. The NRC staff finds that the wording changes in the sentence are of an editorial and clarifying nature and are not material, such that the current intent of the requirement is unchanged. Thus, the NRC staff concludes the first sentence of proposed paragraph 5.5.9.d.2 is acceptable.

4.1.7 <u>Paragraph 5.5.9.d.3 (for plants with SG tubing fabricated from Alloy 600TT)</u>

The first sentence of TS 5.5.9.d.3 currently states:

> If crack indications are found in any portion of a SG tube not excluded above, 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).

<u>Proposed Change</u>: Revise this sentence as follow:

> If crack indications are found in any portion of a SG tube not excluded above, then the next inspection for each affected and potentially affected SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever results in more frequent inspections).

TS 5.5.9.d.3 would be revised, consistent with TSTF-510, to clarify the term "each SG" and to make an editorial change to the parenthetical statement. The application of the permanent alternate plugging criteria of TS 5.5.9.c excludes from required inspection, those portions of each SG tube that are farther below the top of the tubesheet than the calculated H* distance. Adjustment of the inspection interval, based on crack indications in locations that would not otherwise meet inspection and plugging criteria, is not appropriate. Therefore, the phrase "in any portion of a SG not excluded above" is retained to emphasize which crack indications are of interest in determining an adjustment of the inspection interval.

<u>Assessment</u>: Paragraph 5.5.9.d.2 permits SG inspection intervals to extend over multiple fuel cycles for SGs with Alloy 600TT tubing, assuming that such intervals can be implemented while ensuring tube integrity is maintained in accordance with paragraph 5.5.9.d. However, stress corrosion cracks may not become detectable by inspection until the crack depth approaches the tube repair limit. In addition, stress corrosion cracks may exhibit high growth rates. For these reasons, once cracks have been found in any SG tube, paragraph 5.5.9.d.3 restricts the allowable interval to the next scheduled inspection to 24 EFPMs or one refueling outage (whichever is less). The intent of this requirement is that it applies to the affected SG and to any other SG that may be potentially affected by the degradation mechanism that caused the known crack(s). For example, a root cause analysis in response to the initial finding of one or more cracks might reveal that the crack(s) are associated with a manufacturing anomaly that causes locally high residual stress, which in turn caused the early initiation of cracks at the affected locations. If it can be established that the extent of condition of the manufacturing anomaly applies only to one SG and not the others, then the NRC staff agrees that only the affected SG needs to be inspected within 24 EFPMs or one refueling cycle in accordance with paragraph 5.5.9.d.2. The next scheduled inspections of the other SGs will continue to be subject to all other provisions of paragraph 5.5.9.d. The NRC staff finds the proposed change to paragraph 5.5.9.d.3 acceptable, because it clarifies the intent the paragraph.

4.1.8 TS 5.6.8 Steam Generator Tube Inspection Report

TS 5.6.8 currently states:

A report shall be submitted within 180 days after the initial entry into MODE 4 following completion of an inspection performed in accordance with the Specification 5.5.9, Steam Generator (SG) Program. The report shall include:

a. The scope of inspections performed on each SG.

b. Active degradation mechanisms found.

c. Nondestructive examination techniques utilized for each degradation mechanism.

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

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

f. Total number and percentage of tubes plugged to date.

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

h. The primary to secondary leakage rate observed in each SG (if it is not practical to assign the leakage to an individual SG, the entire primary to secondary leakage should be conservatively assumed to be from one SG) during the cycle preceding the inspection that is the subject of the report.

i. The calculated accident induced leakage rate from the portion of the tubes below 17.28 inches from the top of the tubesheet for the most limiting accident in the most limiting SG. In addition, if the calculated accident induced leakage rate from the most limiting accident is less than 1.87 times the maximum operational primary to secondary leakage rate, the report should describe how it was determined, and

j. The results of monitoring for tube axial displacement (slippage). If slippage is discovered, the implications of the discovery and corrective action shall be provided.

Proposed change:

A report shall be submitted within 180 days after the initial entry into MODE 4 following completion of an inspection performed in accordance with the Specification 5.5.9, Steam Generator (SG) Program. The report shall include:

a. The scope of inspections performed on each SG.

b. Degradation mechanisms found.

c. Nondestructive examination techniques utilized for each degradation mechanism.

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

e. Number of tubes plugged during the inspection outage for each degradation mechanism.

f. The number and percentage of tubes plugged to date, and the effective plugging in each steam generator.

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

h. The primary to secondary leakage rate observed in each SG (if it is not practical to assign the leakage to an individual SG, the entire primary to secondary leakage should be conservatively assumed to be from one SG) during the cycle preceding the inspection that is the subject of the report,

i. The calculated accident induced leakage rate from the portion of the tubes below 18.11 inches from the top of the tubesheet for the most limiting accident in the most limiting SG. In addition, if the calculated accident induced leakage rate from the most limiting accident is less than 1.87 times the maximum operational primary to secondary leakage rate, the report should describe how it was determined, and

j. The results of monitoring for tube axial displacement (slippage). If slippage is discovered, the implications of the discovery and corrective action shall be provided.

TS 5.6.8 would be revised, consistent with TSTF-510, to remove the word "active" from TSs 5.6.8.b and 5.6.8.e, and TS 5.6.8.f is revised to require reporting the effective plugging percentage. The value of H* in TS 5.6.8.i is revised consistent with application of the H* methodology to HBRSEP on a permanent basis. The value of the leak rate factor evaluated in WCAP-17091-P, Revision 0 (Reference 3) applicable to the use of the alternate repair criteria at HBRSEP remains unchanged.

<u>Assessment</u>: This proposal would delete the word "active" in items b and e above. Thus, all degradation mechanisms found, whether deemed to be active or not, would now be reportable. The proposed change to item f would add to the HBRSEP SG reporting requirements in order to align with TSTF-510. The proposed value of H* in TS 5.6.8.i is consistent with application of the H* methodology to HBRSEP. The NRC staff finds the proposed changes acceptable since they are more conservative than the current requirements.

4.1.9 TS 3.4.18 "Steam Generator (SG) Tube Integrity"

Limiting Condition for Operation (LCO) 3.4.18, Condition A, and Surveillance Requirement (SR) 3.4.18.2 currently state:

LCO 3.4.18 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.

CONDITION

A. One or more SG tubes satisfying the tube repair criteria and not plugged in accordance with the Steam Generator Program.

SURVEILLANCE

SR 3.4.18.2 Verify that each inspected SG tube that satisfies the tube repair criteria is plugged in accordance with the Steam Generator Program.

Proposed Change:

LCO 3.4.18 SG tube integrity shall be maintained,

AND

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

CONDITION

A. One or more SG tubes satisfying the tube plugging criteria and not plugged in accordance with the Steam Generator Program.

SURVEILLANCE

SR 3.4.18.2 Verify that each inspected SG tube that satisfies the tube plugging criteria is plugged in accordance with the Steam Generator Program.

Assessment: LCO 3.4.18, Condition A, and SR 3.4.18.2, currently references "tube repair criteria" and are revised to "tube plugging criteria" consistent with the changes to TS 5.5.9 based on the implementation of TSTF-510 and recognition that HBRSEP does not have an approved tube repair technique. The NRC staff finds the proposed changes acceptable since they are consistent with the requirements of TSTF-510 and provides consistency with the changes to TS 5.5.9.

4.1.10 Variations from TSTF-510

The licensee proposed variations from TSTF-510, Revision 2, which are described below. These variations are editorial in nature with respect to the applicability of the justifications presented in TSTF-510 and the model safety evaluation prepared by the NRC staff.

The HBRSEP TSs utilize different numbering than NUREG-1431, Revision 3.1, "Standard Technical Specifications Westinghouse Plants" on which the content of TSTF-510 was based. The specific numbering differences are:

	TSTF-510, Revision 2	HBRSEP TS
"Steam Generator Tube Integrity"	3.4.20	3.4.18
"Steam Generator Tube Inspection Report"	5.6.7	5.6.8

4.2 Technical Evaluation of H* Alternate Repair Criteria

The tube-to-tubesheet joints are part of the pressure boundary between the primary and secondary systems. Each tube-to-tubesheet joint consists of the tube, which is hydraulically expanded against the bore of the tubesheet, the tube-to-tubesheet weld located at the tube end, and the tubesheet. The joints were designed in accordance with the ASME Code; Section III, as welded joints, not as friction joints. The tube-to-tubesheet welds were designed to transmit the tube end cap pressure loads, during normal operating and DBA conditions, from the tubes to the tubesheet with no credit taken for the friction developed between the hydraulically-expanded tube and the tubesheet. In addition, the welds serve to make the joints leak tight.

This design basis is a conservative representation of how the tube-to-tubesheet joints actually work, since it conservatively ignores the role of friction between the tube and tubesheet in reacting with the tube end cap loads. The initial hydraulic expansion of the tubes against the tubesheet produces an "interference fit" between the tubes and the tubesheet; thus, producing a residual contact pressure (RCP) between the tubes and tubesheet, which acts normally to the outer surface of the tubes and the inner surface of the tubesheet bore holes. Additional contact pressure between the tubes and tubesheet is induced by operational conditions as will be discussed in detail below. The amount of friction force that can be developed between the outer tube surface and the inner surface of the tubesheet bore is a direct function of the contact pressure between the tube and tubesheet times the applicable coefficient of friction.

To support the proposed TS changes, the licensee's contractor, Westinghouse, has defined a parameter called H*. H* is the distance below the top of the tubesheet over which sufficient frictional force, with acceptable safety margins, can be developed between each tube and the tubesheet under tube end cap pressure loads. The tube end cap pressure loads are associated with normal operating and DBA conditions to prevent significant slippage or pullout of the tube from the tubesheet, assuming the tube is fully severed at the H* distance below the top of the tubesheet. For HBRSEP, the proposed H* distance is 18.11 inches. Given that the frictional force developed in the tube-to-tubesheet joint over the H* distance is sufficient to resist the tube end cap pressure loads, it is the licensee's and Westinghouse's position that the length of tubing between the H* distance and the tube-to-tubesheet weld is not needed to resist any portion of the tube end cap pressure loads. Thus, the licensee is proposing to change the TS to not require inspection of the tubes below the H* distance and to exclude tube flaws located below the H* distance (including flaws in the tube-to-tubesheet weld) from the application of the TS tube repair criteria. Under these changes, the tube-to-tubesheet joint would now be treated as a friction joint extending from the top of the tubesheet to a distance below the top of the tubesheet equal to H* for purposes of evaluating the structural and leakage integrity of the joint.

The regulatory standard by which the NRC staff has evaluated the subject license amendment is that the amended TSs should continue to ensure that tube integrity will be maintained, consistent with the current design and licensing basis. This includes maintaining structural safety margins consistent with the structural performance criteria in TS 5.5.9.b.1 and the design basis, as is discussed in section 4.2.1.1 below. In addition, this includes limiting the potential for accident-induced primary-to-secondary leakage to values not exceeding the accident-induced leakage performance criteria in TS 5.5.9.b.2, which are consistent with values assumed in the licensing basis accident analyses. Maintaining tube integrity in this manner ensures that the amended TSs are in compliance with all applicable regulations. The NRC staff's evaluation of joint structural integrity and accident-induced leakage integrity is discussed in Sections 4.2.1 and 4.2.2 of this safety evaluation, respectively.

4.2.1 Joint Structural Integrity

4.2.1.1 Acceptance Criteria

Westinghouse has conducted extensive analyses to establish the necessary H* distance to resist pullout under normal operating and DBA conditions. The NRC staff concurs that pullout is the structural failure mode of interest since the tubes are radially constrained against axial fishmouth rupture by the presence of the tubesheet. The axial force that could produce pullout derives from the pressure end cap loads due to the primary-to-secondary pressure differentials associated with normal operating and DBA conditions. Westinghouse determined the needed H* distance on the basis of maintaining a factor of three against pullout under normal operating conditions and a factor of 1.4 against pullout under DBA conditions. The NRC staff concurs that these are the appropriate safety factors to apply to demonstrate structural integrity. These safety factors are consistent with the safety factors embodied in the structural integrity performance criteria in TS 5.5.9.b.1 and with the design basis; namely the stress limit criteria in the ASME Code, Section III.

The above approach equates tube pullout to gross structural failure, which is conservative. Should the pullout load be exceeded, tube slippage would generally be limited by the presence of adjacent tubes and support structures such that the tube would not be expected to pull out of the tubesheet.

The licensee has committed in Reference 3 to monitor for tube slippage as part of the SG inspection program. Under the proposed license amendment, TS 5.6.8.j will require that the results of slippage monitoring be included as part of the 180-day report required by TS 5.6.8. TS 5.6.8.j will also require that should slippage be discovered, the implications of the discovery and corrective action shall be included in the report. The NRC staff finds that slippage is not expected to occur for the reasons discussed in this safety evaluation. In the unexpected event it should occur, it will be important to understand why it occurred so that the need for corrective action can be evaluated. The NRC staff concludes the commitment to monitor for slippage and the accompanying reporting requirements are acceptable.

4.2.1.2 Three Dimensional (3-D) Finite Element Analysis

A detailed 3-D finite element analysis (FEA) of the lower SG assembly (consisting of the lower portion of the SG shell, the tubesheet, the channel head, and the divider plate separating the hot- and cold-leg inlet plenums inside the channel head) was performed to calculate tubesheet displacements due to primary pressure acting on the primary face of the tubesheet and SG channel head, secondary pressure acting on the secondary face of the tubesheet and SG shell, and the temperature distribution throughout the entire lower SG assembly. The calculated tubesheet displacements were used as input to the tube-to-tubesheet interaction analysis evaluated in Section 4.2.1.3 below.

The tubesheet bore holes were not explicitly modeled. Instead, the tubesheet was modeled as a solid structure with equivalent material property values selected such that the solid model exhibited the same stiffness properties as the actual perforated tubesheet. This is a classical approach for analyzing perforated plates that the NRC staff finds acceptable.

Two versions of the 3-D FEA model were used to support the subject license amendment request, for an interim H* amendment for Robinson (Reference 5) and a "revised model" described in the technical support document (Reference 10). The reference 3-D FEA model was used to provide displacement input to the thick shell tube-to-tubesheet interaction model described in Section 4.2.1.3.1 below. The revised 3-D FEA model was used to provide displacement input to the square cell tube-to-tubesheet interaction model described in Section 4.2.1.3.2 below. The revised 3-D model employs a revised mesh near the plane of symmetry (perpendicular to the divider plate) to be consistent with the geometry of the square cell model such that the displacement output from the 3-D model can be applied directly to the edges of the square cell model.

Some non-U.S. units have experienced cracks in the weld between the divider plate and the stub runner attachment on the bottom of the tubesheet. Should such cracks ultimately cause the divider plate to become disconnected from the tubesheet, tubesheet vertical and radial displacements under operational conditions could be significantly increased relative to those for an intact divider plate weld. Although the industry understands that there is little likelihood that cracks such as those seen abroad could cause a failure of the divider plate weld, the 3-D FEA conservatively considered both the case of an intact divider plate weld and a detached divider plate weld to ensure a conservative analysis. The case of a detached divider plate weld was found to produce the most limiting H* values. In the reference analyses (Reference 9), a factor was applied to the 3-D FEA results to account for a nonfunctional divider plate, based on earlier sensitivity studies. The revised 3-D FEA model assumes the upper 5 inches of the divider plate to be nonexistent. The NRC staff finds this further improves the accuracy of the 3-D FEA for the assumed condition of a nonfunctional divider plate.

4.2.1.3 Tube-to-Sheet Interaction Model

4.2.1.3.1 Thick Shell Model

The resistance to tube pullout is the axial friction force developed between the expanded tube and the tubesheet over the H* distance. The friction force is a function of the radial contact pressure between the expanded tube and the tubesheet. In the reference analysis (Reference 9), Westinghouse used classical thick-shell equations to model the interaction effects between the tubes and tubesheet under various pressure and temperature conditions for purposes of calculating contact pressure (tube-to-tubesheet interaction model). Calculated displacements from the 3-D FEA of the lower tubesheet assembly (see Section 4.2.1.2 above) were applied to the thick shell model as input to account for the increment of tubesheet bore diameter change caused by the primary pressure acting on the primary face of the tubesheet and SG channel head, secondary pressure acting on the secondary face of the tubesheet and SG shell, and the temperature distribution throughout the entire lower SG assembly. However, the tubesheet bore diameter change from the 3-D FEA tended to be non-uniform (eccentric) around the bore circumference. The thick shell equations used in the tube-to-tubesheet interaction model are axisymmetric. Thus, the non-uniform diameter change from the 3-D FEA had to be adjusted to an equivalent uniform value before it could be used as input to the tube-to-tubesheet interaction analysis. A two dimensional (2-D) plane stress finite element model was used to define a relationship for determining a uniform diameter change that would produce the same change to average tube-to-tubesheet contact pressure, as would the actual non-uniform diameter changes from the 3-D finite element analyses.

In Reference 11, Westinghouse identified a difficultly in applying this relationship to Model D5 SGs under MSLB conditions. In reviewing the reasons for this difficulty, the NRC staff developed questions relating to the conservatism of the relationship and whether the tubesheet bore displacement eccentricities are sufficiently limited such as to ensure that tube-to-tubesheet contact is maintained around the entire tube circumference. This concern was applicable to all SG models with Alloy 600TT tubing. In Reference 12, the NRC staff documented a list of questions that would need to be addressed satisfactorily before the NRC staff would be able to approve a permanent H* amendment. These questions related to the technical justification for the eccentricity adjustment, the distribution of contact pressure around the tube circumference, and a new model under development by Westinghouse to address the aforementioned issue encountered with the Model D5 SGs.

On June 14 and 15, 2010, the NRC staff conducted an audit at the Westinghouse Waltz Mill Site (Reference 13). The purpose of the audit was to gain a better understanding of the H* analysis pertaining to eccentricity, to review draft responses to the NRC staff's questions in Reference 12, and to determine which documents would need to be provided on the docket to support any future requests for a permanent H* amendment. Based on the audit, including review of pertinent draft responses to Reference 12, the NRC staff concluded that eccentricity does not appear to be a significant variable affecting either average tube-to-tubesheet contact pressure at a given elevation or calculated values of H*. The NRC staff found that average contact pressure at a given elevation is primarily a function of average bore diameter change at that elevation associated with the pressure and temperature loading of the tubesheet. Accordingly, the NRC staff concluded that no adjustment of computed average bore diameter change considered in the thick shell model is needed to account for eccentricities computed by the 3-D FEA. The material reviewed during the audit revealed that computed H* values from the reference analyses continued to be conservative when the eccentricity adjustment factor is not applied.

4.2.1.3.2 Square Cell Model

The square cell model is a 2-D plane stress FEA model of a single square cell of the tubesheet with a bore hole in the middle and each of the four sides of the cell measuring one tube pitch in length. Displacement boundary conditions are applied at the edges of the cell, based on the displacement data from the revised 3-D FEA model. The model also includes the tube cross-section inside the bore. Displacement compatibility between the tube outer surface and bore inner surface is enforced except at locations where a gap between the tube and bore could occur.

The square cell model was originally developed in response to the above-mentioned difficulty encountered when applying the eccentricity adjustment to Model D5 SGs tube-to-tubesheet interaction analysis under MSLB conditions using the thick shell model. Early results with this model indicated significant differences compared to the thick shell model, irrespective of whether the eccentricity adjustment was applied to the thick shell model. The square cell model revealed a fundamental problem with how the results of the 3-D FEA model of the lower SG assembly were being applied to the tubesheet bore surfaces in the thick shell model. As discussed in Section 4.2.1.2 above, the perforated tubesheet is modeled in the 3-D FEA model as a solid plate whose material properties were selected such that the gross stiffness of the solid plate is equivalent to that of a perforated plate under the primary-to-secondary pressure acting across the thickness of the plate. This approach tends to smooth out the distribution of tubesheet displacements as a function of radial and circumferential location in the tubesheet, and ignores local variations of the displacements at the actual bore locations. These smoothed out displacements from the 3-D FEA results were the displacements applied to the bore surface locations in the thick shell model. The square cell model provides a means for post-processing the 3-D FEA results to account for localized variations of tubesheet displacement at the bore locations, as part of the tube-to-tubesheet interaction analysis. Based on these findings, square cell models were developed for all of the SG model types including the Model 44F SGs at HBRSEP.

The square cell model is applied to nine different elevations, from the top to the bottom of the tubesheet, for each tube and loading case analyzed. The square cell slices at each elevation are assumed to act independently of one another. Tube-to-tubesheet contact pressure results from each of the nine slices are used to define the contact pressure distribution from the top to the bottom of the tubesheet.

The resisting force to the applied end cap load, which is developed over each incremental axial distance from the top of the tubesheet, is the average contact pressure over that incremental distance multiplied by the tubesheet bore surface area (equal to the tube outer diameter surface area) divided by the incremental axial distance multiplied by the coefficient of friction. The NRC staff reviewed the coefficient of friction used in the analysis and determined that it is a reasonable lower bound (conservative) estimate. The NRC staff determined the H* distance for each tube by integrating the incremental friction forces from the top of the tubesheet to the distance below the top of the tubesheet where the friction force integral equaled the applied end cap load times the appropriate safety factor as discussed in Section 4.2.1.1.

The square cell model assumes as an initial condition that each tube is fully expanded against the tubesheet bore such that the outer tube surface is in contact with the inner surface of the tubesheet bore under room temperature, atmospheric pressure conditions, with zero residual contact pressure from the hydraulic expansion process. The NRC staff finds the assumption of zero residual contact pressure in all tubes to be a conservative assumption.

Westinghouse determined the limiting tube locations in terms of H* during the reference analysis to lie along the plane of symmetry perpendicular to the divider plate. The outer edges of the square cell model conform to the revised mesh pattern along this plane of symmetry in the 3-D FEA model of the lower SG assembly, as discussed in Section 4.2.1.2. Because the tubesheet bore holes were not explicitly modeled in the 3-D FEA, only the average displacements along each side of the square cell are known from the 3-D FEA. Three different assumptions for applying displacement boundary conditions to the edges of the square cell model were considered to allow for a range of possibilities about how local displacements might vary along the length of each side. The most conservative assumption, in terms of maximizing the calculated H* distance, was to apply the average transverse displacement uniformly over the length of each edge of the square cell model.

Primary pressure acting on the inside tube surface and crevice pressure[1] acting on both the tube outside surface and tubesheet bore surface are not modeled directly as in the case of the thick shell model. Instead, Westinghouse assumed the primary side (inside) of the tube to have a pressure equal to the primary pressure minus the crevice pressure. Note the crevice pressure varies as a function of the elevation being analyzed, as discussed in Section 4.2.1.4.

The NRC staff concludes that the square cell model provides for improved compatibility between the 3-D FEA model of the lower SG assembly and the tube-to-tubesheet interaction model, more realistic and accurate treatment of the tube-to-tubesheet joint geometry, and added conservatism relative to the thick shell model used in the reference analyses.

4.2.1.4 Crevice Pressure Evaluation

The licensee H* analyses postulate that interstitial spaces exist between the hydraulically expanded tubes and tubesheet bore surfaces. The licensee assumed that these interstitial spaces act as crevices between the tubes and the tubesheet bore surfaces. The NRC staff finds that the assumption of crevices is conservative since the pressure inside the crevices acts to push against both the tube and the tubesheet bore surfaces, thus reducing contact pressure between the tubes and tubesheet.

For tubes that do not contain through-wall flaws within the thickness of the tubesheet, the licensee assumed that the pressure inside the crevice to be equal to the secondary system pressure. For tubes that contain through-wall flaws within the thickness of the tubesheet, the

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[1] Although the tubes are in tight contact with the tubesheet bore surfaces, surface roughness effects are conservatively assumed to create interstitial spaces, which are effectively crevices, between these surfaces. See Section 4.2.1.4 for more information.

licensee assumed a leak path to exist, from the primary coolant inside the tube, through the flaw, and up the crevice to the secondary system. Hydraulic tests were performed on several tube specimens that were hydraulically expanded against tubesheet collar specimens to evaluate the distribution of the crevice pressure from a location where through-wall holes had been drilled into the tubes to the top of the crevice location. The licensee instrumented tube-to-tubesheet collar specimens at several axial locations to permit direct measurement of the crevice pressures. The licensee ran tests for both normal operating and MSLB pressure and temperature conditions.

The NRC staff finds that the use of the drilled holes, rather than through-wall cracks, is conservative since it eliminates any pressure drop between the inside of the tube and the crevice at the whole location. This maximizes the pressure in the crevice at all elevations, thus reducing contact pressure between the tubes and tubesheet.

The licensee used crevice pressure data from these tests to develop a crevice pressure distribution as a function of normalized distance between the top of the tubesheet and the H* distance below the top of the tubesheet where the tube is assumed to be severed. The licensee used these distributions to determine the appropriate crevice pressure at each axial location of the tube-to-tubesheet interaction model. The NRC staff concluded that these distributions are acceptable for this purpose.

Because the crevice pressure distribution is assumed to extend from the H* location, where crevice pressure is assumed to equal primary pressure, to the top of the tubesheet, where crevice pressure equals secondary pressure, an initial estimate as to the H* location must be made before solving for H* using the tube-to-tubesheet interaction model and 3-D finite element model.

The resulting new H* estimate becomes the initial estimate for the next H* iteration.

4.2.1.5 H* Calculation Process

The licensee's calculation of H* consisted of the following steps for each loading case considered:

1. Perform initial H* estimate (mean H* estimate) using the tube-to-tubesheet interaction model and 3-D FEA models, assuming nominal geometric and material properties, and assuming that the tube is severed at the bottom of the tubesheet for purposes of defining the contact pressure distribution over the length of the tube-to-tubesheet crevice. Two sets of mean H* estimates are pertinent to the proposed H* value, mean H* estimates calculated with the reference tube-to-tubesheet interaction and 3-D FEA models, and mean H* estimates calculated with the square cell tube-to-tubesheet interaction and revised 3-D FEA models. The maximum, mean H* estimate (for the most limiting tube) from the reference analysis is 4.53 inches, for the most limiting case of normal operating conditions (with the associated factor of safety of 3 as evaluated in section 4.2.1.1). This estimate includes the adjustment in item 2 below. The maximum, mean H* estimate with the square cell model in conjunction with the revised 3-D lower SG FEA model is 7.877 inches. Again, the most limiting loading case for this revised analysis is normal operating conditions. The NRC staff finds that the difference in mean H* estimates

between the reference analysis and the revised analysis is dominantly due to the improved post-processing of the 3-D FEA model displacements for application to the tube-to-tubesheet interaction model.

2. In the reference analysis (Reference 9), a 0.3-inch adjustment was added to the initial H* estimate to account for uncertainty in the bottom of the tube expansion transition (BET) location relative to the top of the tubesheet, based on an uncertainty analysis on the BET for Model F SGs conducted by Westinghouse. This adjustment is not included in the revised H* analysis accompanying the subject amendment request amendment, as discussed and evaluated in Section 4.2.1.5.1 of this safety evaluation.

3. Steps 1 and 2 yield a so-called "mean" estimate of H*, which is deterministically based. Step 3 involves a probabilistic analysis of the potential variability of H*, relative to the mean estimate, associated with the potential variability of key input parameters for the H* analyses. This leads to a "probabilistic" estimate of H*, which includes the mean estimate. The NRC staff's evaluation of the probabilistic analysis is provided in Sections 4.2.1.6 and 4.2.1.7 of this safety evaluation.

4. Add a crevice pressure adjustment to the probabilistic estimate of H* to account for the crevice pressure distribution which results from the tube being severed at the final H* value, rather than at the bottom of the tubesheet. This step is discussed and evaluated in Section 4.2.1.5.2 of this safety evaluation.

5. This step has been added to the H* calculation process since the reference analysis to support the subject amendment request. This step adds an additional adjustment to the probabilistic estimate of H*, to account for the Poisson contraction of the tube radius due to the axial end cap load acting on each tube. This step is discussed and evaluated in Section 4.2.1.5.3 of this safety evaluation.

4.2.1.5.1 BET Considerations

The diameter of each tube transitions from its fully expanded value to its unexpanded value near the top of the tubesheet. The BET region is located a short distance below the top of tubesheet so as to avoid any potential for over-expanding the tube above the top of the tubesheet. In the reference H* analysis (Reference 9), a 0.3-inch adjustment was added to the mean H* estimate to account for the BET location being below the top of the tubesheet based on an earlier survey of BET distances conducted by Westinghouse. The licensee found that this adjustment was necessary since the reference analysis did not explicitly account for the lack of contact between the tube and tubesheet over the BET distance.

The licensee subsequently performed BET measurements, based on eddy current testing, for all tubes at HBRSEP. These measurements confirm that the original 0.3 inch BET assumption is bounding on a 95-percentile basis; but that maximum values at HBRSEP range up to 1.12 inches.

The licensee's most recent H* analyses using the square cell tube-to-tubesheet interaction model (Reference 10) has made the need for a BET adjustment unnecessary, as the square cell Model shows a loss of contact pressure over a distance from the top of the tubesheet that is greater than the possible variation in the BET location. This observation applies to all radial locations with local mean H* values within 1 inch of the maximum, mean H* value. The loss of contact pressure at the top of the tubesheet shown in the square cell Model (which is unrelated to BET location) is compensated for by a steeper contact pressure gradient than was shown previously in the thick shell model H* analysis. The NRC staff concludes that the proposed H* value adequately accounts for the range of BET values at HBRSEP.

4.2.1.5.2 Crevice Pressure Adjustment

As discussed in Section 4.2.1.5, the licensee performed steps 1 through 3 of the H* calculation process leading to a probabilistic H* estimate with the assumption that the tube is severed at the bottom of the tubesheet for purposes of calculating the distribution of crevice pressure as a function of elevation. If the tube is assumed to be severed at the initially computed H* distance and steps 1 through 3 repeated, a new H* may be calculated that will be incrementally larger than the first estimate. This process may be repeated until the change in H* becomes small (convergence). Sensitivity analyses conducted with the thick shell model showed that the delta between the initial H* estimate and final (converged) estimate is a function of the initial estimate for the tube in question. This delta (i.e., the crevice pressure adjustment referred to in step 4 of Section 4.2.1.5) was plotted as a function of the initial H* estimate for the limiting loading case and tube radial location. Although the licensee conducted the sensitivity study with the thick shell model, the deltas from this study were used in the Reference 10 (square cell model) analysis to make the crevice pressure adjustment to H*. Updating this sensitivity study would have been very resource intensive, requiring many new 2-D FEA square cell runs.

In response to an NRC staff question as to whether it is conservative to rely on the existing sensitivity study as opposed to updating it to reflect the square cell model, Westinghouse submitted an analysis (Reference 14) demonstrating that if the sensitivity study were updated, it would show that the crevice pressure adjustment H* is negative, not positive as is shown by the existing study. This is because the square cell model predicts a much longer zone (6 inches) of no tube-to-tubesheet contact below the top of the tubesheet than does the thick shell model. Therefore, the crevice pressure must reduce from primary side pressure at the iterative H* location to secondary side pressure 6 inches below the top of the tubesheet. This leads to higher predicted pressure differentials across the tube wall over the iterative H* distance than exists during the initial iteration when crevice pressure is initially assumed to vary from primary pressure at the very bottom of the tubesheet to secondary pressure at the very top of the tubesheet. Based on its review of the Westinghouse analysis, the NRC staff concludes that the positive crevice pressure adjustment to H* in the Reference 10 analysis, which is based on the existing sensitivity study, is conservative and that an updated sensitivity analysis based on use of the square cell model would show that a negative adjustment can be justified. Thus, the NRC staff concludes the crevice pressure adjustment performed in support of the proposed H* amendment is conservative and acceptable.

4.2.1.5.3 Poisson Contraction Effect

The axial end cap load acting on each tube is equal to the primary-to-secondary pressure difference times the tube cross-sectional area. For purposes of resisting tube pullout under normal and accident conditions, the end cap loads the licensee used in the H* analyses are based on the tubesheet bore diameter, which the NRC staff finds to be a conservative assumption. The axial end cap load tends to stretch the tube in the axial direction, but causes a slight contraction in the tube radius due to the Poisson's Ratio effect. This effect, by itself, tends to reduce the tube-to-tubesheet contact pressure and, thus, to increase the H* distance. The axial end cap force is resisted by the axial friction force developed at the tube-to-tubesheet joint. Thus, the axial end cap force begins to decrease with increasing distance into the tubesheet, reaching zero at a location before the H* distance is reached. This is because the H* distances are intended to resist pullout under the end cap loads with the appropriate factors of safety applied as discussed in Section 4.2.1.1.

The licensee took a simplified approach to account for the Poisson radial contraction effect. First, thick shell equations were used to estimate the reduction in contact pressure associated with application of the full end cap load, assuming none of this end cap load has been reacted by the tubesheet. The tube-to-tubesheet contact pressure distributions determined in the H* calculation process (in Section 4.2.1.5) were reduced by this amount. Second, the licensee integrated the friction force associated with these reduced tube-to-tubesheet contact pressures with distance into the tubesheet, and the length of engagement necessary to react one times the end cap loading (i.e., no safety factor applied) was determined. At this distance (termed attenuation distance by Westinghouse), the entire end cap loading was assumed to have been reacted by the tubesheet, and the axial load in the tube below the attenuation distance was assumed to be zero. Thus, the tube-to-tubesheet contact pressures below the attenuation distance were assumed to be unaffected by the Poisson radial contraction effect. Finally, the licensee calculated a revised H* distance, where the tube-to-tubesheet contact pressures from Section 4.2.1.5 were reduced only over the attenuation distance.

The NRC staff finds the simplified approach for calculating the H* adjustment for the Poisson contraction effect to contain significant conservatism relative to a more detailed approach. Regarding the safety factor of unity assumption, Westinghouse states that it is unrealistic to apply a safety factor to a physical effect such as Poisson's ratio. The NRC staff has not reached a conclusion on this point. However, irrespective of whether a safety factor is applied to the Poisson's contraction effect (consistent with Section 4.2.1.1 above), the NRC staff concludes there is ample conservatism embodied in the proposed H* distance to accommodate the difference.

4.2.1.6 Acceptance Standard - Probabilistic Analysis

The purpose of the licensee's probabilistic analysis is to develop an H* distance that ensures with a probability of 0.95 that the population of tubes will retain margins against pullout consistent with criteria evaluated in Section 4.2.1.1 of this safety evaluation, assuming all tubes to be completely severed at their H* distance. The NRC staff finds this probabilistic acceptance standard is consistent with what the NRC staff has approved previously and is acceptable. For example, the upper voltage limit for the voltage based tube repair criteria in NRC Generic Letter 95-05 (Reference 15) employs a consistent criterion. The NRC staff also notes that use of the 0.95 probability criterion ensures that the probability of pullout of one or more tubes under normal operating conditions and conditional probability of pullout under accident conditions is well within tube rupture probabilities that have been considered in probabilistic risk assessments (References 16 and 17).

In terms of the confidence level that should be attached to the 0.95 probability acceptance standard, it is industry practice for SG tube integrity evaluations, as embodied in industry guidelines, to calculate such probabilities at a 50-percent confidence level. The NRC staff has been encouraging the industry to revise its guidelines to call for calculating such probabilities at a 95-percent confidence level when performing operational assessments and a 50-percent confidence level when performing condition monitoring (Reference 18). In the meantime, the calculated H* distances supporting the amendment currently being requested have been evaluated at the 95-percent confidence level, as recommended by the NRC staff.

Another issue relating to the acceptance standard for the probabilistic analysis is determining what population of tubes needs to be analyzed. For accidents such as MSLB or feed line break, the NRC staff and licensee agree that the tube population in the faulted SG is of interest, since it is the only SG that experiences a large increase in the primary-to-secondary pressure differential. However, normal operating conditions were found to be the most limiting in terms of meeting the tube pullout margins in Section 4.2.1.1. For normal operating conditions, tubes in all SGs at the plant are subject to the same pressures and temperatures. Although there is not a consensus between the NRC staff and industry on which population needs to be considered in the probabilistic analysis for normal operating conditions, the calculated H* distances for normal operating conditions supporting the requested amendment are 0.95 probability/95 percent confidence estimates based on the entire tube population for the plant, consistent with the NRC staff's recommendation.

Based on the above, the NRC staff concludes that the proposed H* distance in the subject license amendment request is based on acceptable probabilistic acceptance standards evaluated at acceptable confidence levels.

4.2.1.7 Probabilistic Analyses

4.2.1.7.1 Reference Analyses

Sensitivity studies were conducted during the reference analyses (Reference 9) and demonstrated that H* was highly sensitive to the potential variability of the coefficients of thermal expansion (CTE) for the Alloy 600 tubing material and the SA-508 Class 2a tubesheet material. Given that no credit was taken in the reference H* analyses (Reference 9) for residual contact pressure associated with the tube hydraulic expansion process,[2] the sensitivity of H* to other geometry and material input parameters was judged by Westinghouse to be inconsequential and were ignored, with the exception of Young's modulus of elasticity for the tube and tubesheet materials. Although the Young's modulus parameters were included in the reference H* analyses sensitivity studies, these parameters were found to have a weak effect on the computed H*. Based on its review of the analysis models and its engineering judgment, the NRC staff concurs that the sensitivity studies adequately capture the input parameters, which may significantly affect the value of H*. This conclusion is based, in part, on no credit being taken for RCP during the reference H* analyses.

These sensitivity studies were used to develop influence curves describing the change in H*, relative to the mean H* value estimate (See section 4.2.1.5), as a function of the variability of

[2] Residual contact pressures are sensitive to variability of other input parameters.

each CTE parameter and Young's modulus parameter, relative to the mean values of CTE and Young's Modulus. Separate influence curves were developed for each of the four input parameters. The sensitivity studies showed that of the four input parameters, only the CTE parameters for the tube and tubesheet material had any interaction with one another. A combined set of influence curves containing this interaction effect were also created.

Two types of probabilistic analyses were performed independently in the reference analyses. One was a simplified statistical approach utilizing a "square root of the sum of the squares" method and the other was a detailed Monte Carlo sampling approach. The NRC staff's review of the reference analysis relied on the Monte Carlo analysis, which provides the most realistic treatment of uncertainties. The NRC staff reviewed the implementation of probabilistic analyses in the reference analyses and questioned whether the H* influence curves had been conservatively treated. To address this concern, Westinghouse performed new H* analyses as documented in References 19 and 20. These analyses made direct use of the H* influence curves in a manner the NRC staff finds to be acceptable.

The revised reference analyses in Reference 19 divided the tubes by sector location within the tube bundle and all tubes were assumed to be at the location in their respective sectors where the initial value of H* (based on nominal values of material and geometric input parameters) was at its maximum value for that sector. The H* influence curves discussed above, developed for the most limiting tube location in the tube bundle, were conservatively used for all sectors. The revised reference analyses also addressed a question posed by the NRC staff concerning the appropriate way to sample material properties for the tubesheet, whose properties are unknown but do not vary significantly for a given SG, in contrast to the tubes whose properties tend to vary much more randomly from tube to tube in a given SG. This issue was addressed by a staged sampling process where the tubesheet properties were sampled once and then held fixed, while the tube properties were sampled a number of times equal to the SG tube population. This process was repeated 10,000 times, and the maximum H* value from each repetition was rank ordered. The final H* value was selected from the rank ordering to reflect a 0.95 probability value at the desired level of confidence for a single SG tube population or all SG population, as appropriate. The NRC staff concludes that this approach addresses the NRC staff's question in a realistic fashion and is acceptable.

4.2.1.7.2 Revised Analyses to Reflect Square Cell and Revised 3-D FEA Models

The licensee did not perform new Monte Carlo analyses using the square cell model to evaluate the statistical variability of H* due to the CTE variability for the tube and tubesheet materials. This was because such an approach would have been extremely resource intensive and because a simpler approach involving good approximation was available. The simplified approach involved using the results of the Monte Carlo analyses from the reference analysis, which are based on the thick shell tube-to-tubesheet interaction model, to identify CTE values for the tube and tubesheet associated with the probabilistic H* values near the desired rank ordering.

Tube CTE values associated with the upper 10 percent rank order estimates are generally negative variations from the mean value whereas tubesheet CTE values associated with the higher ranking order estimates are generally positive variations from the mean value. For the upper 10 percent of the Monte Carlo results ranking order, the licensee defined a combined uncertainty parameter, "alpha," as the square root of the sum of the squares of the associated tube and tubesheet CTE values for each Monte Carlo sample. The licensee plotted alpha as a function of the corresponding H* estimate and separately as a function of rank order. Each of these plots exhibited well-defined "break lines," representing the locus of maximum H* estimates and maximum rank orders associated with a given values of alpha. From these plots, the licensee selected three paired sets of tube and tubesheet CTE values, located near the break line. The licensee then input these CTE values to the lower SG assembly 3-D FEA model and the square cell model to yield probabilistic H* estimates which approximate the H* values for these same rank orderings had a full Monte Carlo been performed with the square cell and revised 3-D FEA models. The licensee then plotted these H* estimates as a function of rank ordering, allowing the interpolation of H* values at the other rank orders. The resulting 95/95 upper bound H* estimate is 15.75 inches, which compares to the mean estimate of 7.877 inches as discussed in Section 4.2.1.5. With adjustments for Poisson's contraction (see Section 4.2.1.5.3) and crevice pressure (Section 4.2.1.5.2), the final 95/95 upper bound H* estimate is 18.11 inches which is the value in the subject amendment request.

The NRC staff considers that the above break line approach to be a very good approximation of what an actual Monte Carlo would show. A perfect approximation would mean that if hypothetically one were to perform a square cell analysis for each paired set of tube and tubesheet CTE values associated with the top 10 percent of rank orders and plot the resulting H* values versus the original rank ordering associated with the CTE couple, the calculated H* values should monotonically increase from rank order to rank order. Westinghouse performed additional square cell analyses with CTE pairs for five consecutive rank orders for both Model D5 and Model F SGs. The results showed deviations from monotonically increasing values of H* with rank order to be on the order of only 0.3 inches for the Model D5 SGs and 0.1 inches for the Model F SGs. The NRC staff considers these deviations to be representative for the Model 44F SGs at HBRSEP. The NRC staff concludes that use of the break line approach adds little imprecision to the probabilistic H* estimates and is acceptable.

4.2.1.8 Coefficient of Thermal Expansion

During operation, a large part of contact pressure in a SG tube-to-tubesheet joint is derived from the difference in CTE between the tube and tubesheet. As discussed in section 4.2.1.7, the calculated value of H* is highly sensitive to the assumed values of these CTE parameters. However, CTE test data acquired by an NRC contractor, Argonne National Laboratory (ANL), suggested that CTE values may vary substantially from values listed in the ASME Code for design purposes. In Reference 21, the NRC staff highlighted the need for a rigorous technical basis of the CTE values, and their potential variability, to be employed in future H* analyses.

In response, Westinghouse had a subcontractor review the CTE data in question, determine the cause of the variance from the ASME Code CTE values, and provide a summary report (Reference 22). Analysis of the CTE data in question revealed that the CTE variation with temperature had been developed using a polynomial fit to the raw data, over the full temperature range from 75 degrees Fahrenheit (°F) to 1300 °F. The polynomial fit the subcontracted chose resulted in mean CTE values that were significantly different from the ASME Code values from 75 °F to about 300 °F. When the subcontractor reanalyzed the raw data using the locally weighted least squares regression method, the mean CTE values determined were in good agreement with the established ASME Code values.

Westinghouse also formed a panel of licensee experts to review the available CTE data in open literature, review the ANL provided CTE data, and perform an extensive CTE testing program on Alloy 600 and SA-508 steel material to supplement the existing data base. Two additional sets of CTE test data (different from those addressed in the previous paragraph) had CTE offsets at low temperatures that were not expected. Review of the test data showed that the first test, conducted in a vacuum, had proceeded to a maximum temperature of 1300 °F, which changed the microstructure and the CTE of the steel during decreasing temperature conditions. As a result of the altered microstructure, the CTE test data generated in the second test, conducted in air, was also invalidated. As a result of the large "dead band" region and the altered microstructure, both data sets were excluded from the final CTE values obtained from the CTE testing program. The test program included multiple material heats to analyze chemistry influence on CTE values and repeat tests on the same samples were performed to analyze for test apparatus influence. Because the tubes are strain hardened when they are expanded into the tubesheet, strain hardened samples were also measured to check for strain hardening influence on CTE values.

The data from the test program was combined with the ANL data that was found to be acceptable and the data obtained from the open literature search. A statistical analysis of the data uncertainties was performed by comparing deviations to the mean values obtained at the applicable temperatures. The correlation coefficients obtained indicated a good fit to a normal distribution, as expected. Finally, an evaluation of within-heat variability was performed due to increased data scatter at low temperatures. The within-heat variability assessment determined that the increase in data scatter was a testing accuracy limitation that was only present at low temperature. The CTE report is included as Appendix A to Reference 9.

The testing showed that the nominal ASME Code values for Alloy 600 and SA-508 steel were both conservative relative to the mean values from all the available data. Specifically, the CTE mean value for Alloy 600 was greater than the ASME Code value and the CTE mean value for SA-508 steel was smaller than the ASME Code value. Thus, the H* analyses utilized the ASME Code values as mean values in the H* analyses. The NRC staff finds this to be conservative because it tends to lead to an over-prediction of the expansion of the tubesheet bore and an under-prediction of the expansion of the tube, thereby resulting in an increase in the calculated H* distance. The statistical variances of the CTE parameters from the combined data base were utilized in the H* probabilistic analysis.

Based on its review of the Westinghouse CTE program, the NRC staff concludes that the CTE values used in the H* analyses are fully responsive to the concerns stated in Reference 21 and are acceptable.

4.2.2 Leakage Considerations

Operational leakage integrity is assured by monitoring primary-to-secondary leakage relative to the applicable TS loss-of-coolant LCO limits in TS 3.4.13, "RCS [Reactor Coolant System] Operational LEAKAGE." However, it must also be demonstrated that the proposed TS changes do not create the potential for leakage during DBA to exceed the accident leakage performance criteria in TS 5.5.9.b.2, which are based on the leakage values assumed in the plant licensing basis accident analyses.

If a tube is assumed to contain a 100-percent through-wall flaw some distance into the tubesheet, a potential leak path between the primary and secondary systems is introduced between the hydraulically expanded tubing and the tubesheet. The leakage path between the tube and tubesheet has been modeled by the licensee's contractor, Westinghouse, as a crevice consisting of a porous media. Using Darcy's model for flow through a porous media, leak rate is proportional to differential pressure and inversely proportional to flow resistance. Flow resistance is a direct function of viscosity, loss coefficient, and crevice length.

Westinghouse performed leak tests of tube-to-tubesheet joint mockups to establish loss coefficient as a function of contact pressure. A large amount of data scatter, however, precluded quantification of such a correlation. In the absence of such a correlation, Westinghouse has developed a leakage factor relationship between accident induced leak rate and operational leakage rate, where the source of leakage is from flaws located at or below the H* distance.

Using the Darcy model, the leakage factor for a given type accident is the product of four quantities. The first quantity is ratio of the maximum primary-to-secondary pressure difference during the accident divided by that for normal operating conditions. The second quantity is the ratio of viscosity under normal operating primary water temperature divided by viscosity under the accident condition primary water temperature. The third quantity is the ratio of crevice length under normal operating conditions to crevice length under accident conditions. This ratio equals 1, provided it can be shown that positive contact pressure is maintained along the entire H* distance for both conditions. The fourth quantity is the ratio of loss coefficient under normal operating conditions to loss coefficient under the accident condition. Although the absolute value of these loss coefficients is not known, Westinghouse has assumed that the loss coefficient is constant with contact pressure such that the ratio is equal to 1. The NRC staff agrees that this is a conservative assumption, provided there is a positive contact pressure for both conditions along the entire H* distance and provided that contact pressure increases at each axial location along the H* distance when going from normal operating to accident conditions. The NRC staff confirmed that both assumptions are valid in the H* analyses.

The licensee calculated leakage factors for DBAs exhibiting a significant increase in primary-to-secondary pressure differential, including MSLB, locked rotor, and control rod ejection. The licensee found the design basis MSLB transient to exhibit the highest leakage factor, 1.87, meaning that it is the transient expected to result in the largest increase in leakage relative to normal operating conditions.

In Reference 3, the licensee provided a commitment describing how the leakage factor will be used to satisfy TS 5.5.9.a for condition monitoring and TS 5.5.9.b.2 regarding performance criteria for accident induced leakage:

> *For the condition monitoring assessment, the component of operational leakage from the prior cycle from below the H* distance will be multiplied by a factor of 1.87 and added to the total accident leakage from any other source and compared to the allowable accident induced leakage limit. For the operational*

assessment, the difference in the leakage between the allowable accident induced leakage and the accident induced leakage from sources other than the tubesheet expansion region will be divided by 1.87 and compared to the observed operational leakage. An administrative limit will be established to not exceed the calculated value.

Extensive industry guidance on conducting condition monitoring and operational assessments is available as part of the industry NEI 97-06 initiative (Reference 23). The NRC staff has determined that the above commitments ensure that plant procedures address the above leakage factor issue and industry guidelines.

The subject amendment request includes reporting requirements (TS 5.6.8.i and TS 5.6.8.j) relating to operational leakage existing during the cycle preceding each SG inspection and condition monitoring assessment, and the associated potential for accident induced leakage from the lower portion of the tubesheet below the H* distance. These reporting requirements will allow the NRC staff to monitor how the leakage factor is actually being used, therefore, the NRC staff finds them to be acceptable.

4.3 TSTF-510 Implementation

In addition to the changes proposed to reflect the implementation of the H* alternate repair criteria, the licensee also proposed to adopt the changes specified in TSTF-510, Revision 2, for HBRSEP. The changes in TSTF-510, Revision 2, reflect licensees' early implementation experience with their current TSs. The changes in TSTF-510, Revision 2, are editorial corrections, changes, and clarifications intended to improve internal consistency, consistency with implementing industry documents, and usability, without changing the intent of the requirements. The proposed changes are an improvement to the existing SG inspection requirements and continue to provide assurance that the plant licensing basis will be maintained between SG inspections. The NRC staff approved TSTF-510, Revision 2 for use with the consolidated line item process on October 19, 2011 (Reference 7). Other than wording variations discussed previously in "Proposed Changes to the Technical Specifications" (which reflected the implementation of the H* alternate repair criterion), and those discussed below, the licensee is not proposing any variations from the TS changes described in the TSTF-510, Revision 2.

The HBRSEP TSs utilize different numbering and titles than the Standard TSs on which TSTF-510, Revision 2, was based. These differences are administrative and do not affect the applicability of TSTF-510, Revision 2, to the HBRSEP TSs. As a result, the NRC staff finds that the differences between what was approved for TSTF-510, Revision 2, and what is being proposed, are acceptable.

In summary, the NRC staff finds that the proposed changes to the SG TSs are acceptable, since the resultant TSs are consistent with TSTF-510, Revision 2, and the H* alternate repair criterion. The staff's basis for concluding TSTF-510, Revision 2, is acceptable is documented in the model safety evaluation dated October 19, 2011 (Reference 24).

5.0 Summary and Conclusions

Since the initial proposal for a permanent H* amendment in 2009, the licensee has substantially revised and refined the supporting technical analyses to address NRC staff questions and issues. The current analyses supporting the proposed permanent amendment still embody uncertainties and issues (e.g., should a factor of safety be applied to the Poisson's contraction effect) as discussed throughout this safety evaluation. However, it is important to acknowledge that there are significant conservatisms in the analyses. Some examples, also discussed elsewhere in this safety evaluation, include taking no credit for residual contact pressures associated with the hydraulic tube expansion process, the assumed value of 0.2 for coefficient of friction between the tube and tubesheet, and taking no credit for constraint against pullout provided by adjacent tubes and support structures. The NRC staff has evaluated the potential impact of the uncertainties and concludes these uncertainties to be adequately bounded by the significant conservatism within the analyses and proposed H* distance.

The NRC staff finds the proposed changes to the HBRSEP TSs ensure that tube structural and leakage integrity will be maintained with structural safety margins consistent with the design basis and with leakage integrity within assumptions employed in the licensing basis accident analyses, without undue risk to public health and safety. Based on this finding, the NRC staff further concludes that the proposed amendment meets the requirements of 10 CFR 50.36 and, therefore, finds the proposed amendment is acceptable.

6.0 STATE CONSULTATION

In accordance with the Commission's regulations, the State of South Carolina official was notified of the proposed issuance of the amendment. The State official had no comments.

7.0 ENVIRONMENTAL CONSIDERATION

The amendment changes a requirement with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20 and change the surveillance requirements. The NRC staff has determined that the amendment involves no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendment involves no significant hazards consideration, and there has been no public comment on such finding (77 FR 63348). Accordingly, the amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendment.

8.0 CONCLUSION

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

9.0 REFERENCES

1. Carolina Power and Light Company, "H. B. Robinson Steam Electric Plant, Unit 2 – License Amendment Request for Revision to Steam Generator Program Inspection Frequencies and Tube Sample Selection and Application of Permanent Alternate Repair Criteria (H*)," August 29, 2012 (NRC ADAMS Accession No. ML12251A363).

2. Carolina Power and Light Company, "H. B. Robinson Steam Electric Plant, Unit 2 – Response to Request for Additional Information for Review Regarding Steam Generator License Amendment Request to Revise Technical Specifications for Steam Generator Permanent Alternate Repair Criteria," March 6, 2013 (NRC ADAMS Accession No. ML13072A300).

3. Carolina Power and Light Company, "H. B. Robinson Steam Electric Plant, Unit 2 – Revision to License Amendment Request for Revision to Steam Generator Program Inspection Frequencies and Tube Sample Selection and Application of Permanent Alternate Repair Criteria," April 9, 2013 (NRC ADAMS Accession No. ML13123A221).

4. NRC letter to Carolina Power & Light Company, "H. B. Robinson Steam Electric Plant, Unit No. 2 – Issuance of an Amendment on Steam Generator Tube Repair in the Tubesheet," April 9, 2007 (NRC ADAMS Accession No. ML070920008).

5. NRC letter to Carolina Power and Light Company, "H. B. Robinson Steam Electric Plant, Unit No.2 - Issuance of Amendment Regarding Technical Specifications Changes Related to the Steam Generator Alternate Repair Criteria," May 7, 2010 (NRC ADAMS Accession No. ML100990405).

6. NRC letter to Florida Power and Light Company, "Turkey Point Nuclear Generating Station Unit Nos. 3 and 4 – Issuance of Amendments Regarding Permanent Alternate Repair Criteria for Steam Generator Tubes," November 5, 2012 (NRC ADAMS Accession No. ML12292A342).

7. NRC Notice of Availability, "Models for Plant-Specific Adoption of Technical Specifications Task Force Traveler TSTF-510, Revision 2, "Revision to Steam Generator Program Inspection Frequencies and Tube Sample Selection," October 19, 2011 (ADAMS Accession No. ML112101604).

8. Technical Specification Task Force (TSTF) Letter to NRC, TSTF-12-09, "Correction to TSTF-510-A, Revision 2, Revision to Steam Generator Program Inspection Frequencies and Tube Sample Selection" March 28, 2012 (ADAMS Accession No. ML12088A082).

9. H. B. Robinson Steam Electric Plant, Unit 2, WCAP-17091-NP (Non-Proprietary), Rev. 0, "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model 44F)," June 2009; NRC ADAMS Accession No. ML093631213. See ML093631213, which is an attachment to ML093631200 for

H.B. Robinson, Unit 2 – Request for Technical Specification Change Regarding Steam Generator Alternate Repair Criteria.

10. Westinghouse Electric Company, LLC, WCAP-17345-P (Proprietary) and WCAP-17345-NP (Nonproprietary), Rev. 2, "H*: Resolution of NRC Technical Issue Regarding Tubesheet Bore Eccentricity (Three Loop Model 44F/Model 51F)," June 2011; NRC ADAMS Accession No. ML11215A059 (Nonproprietary).

11. Westinghouse Electric Company (WEC) report, WCAP-17072-P (Proprietary) and WCAP-17072-NP (Nonproprietary), Rev. 0, "H*: Alternate Repair Criteria for the Tubesheet Expansion Region in Steam Generators with Hydraulically Expanded Tubes (Model D5)," May 2009; NRC ADAMS Accession No. ML101730389 (Nonproprietary).

12. NRC letter to Southern Nuclear Operating Company, "Vogtle Electric Generating Plant, Units 1 and 2, Transmittal of Unresolved Issues Regarding Permanent Alternate Repair Criteria for Steam Generators," November 23, 2009; NRC ADAMS Accession No. ML093030490.

13. NRC memorandum, R. Taylor to G. Kulesa, "Vogtle Electric Generating Plant – Audit of Steam Generator H* Amendment Reference Documents," July 9, 2010; NRC ADAMS Accession No. ML101900227.

14. Virginia Electric and Power Company, "Surry Power Station Units 1 and 2 – Response to Request for Additional Information Related to License Amendment Request for Permanent Alternate Repair Criteria for Steam Generator Tube Inspection and Repair," February 14, 2012; NRC ADAMS Accession No. ML12048A676.

15. NRC Generic Letter 95-05, "Voltage Based Alternate Repair Criteria for Westinghouse Steam Generator Tubes Affected by Outside Diameter Stress Corrosion Cracking," August 3, 1995; NRC ADAMS Accession No. ML031070113.

16. NUREG-0844, "NRC Integrated Program for the Resolution of Unresolved Safety Issues A-3, A-4, and A-5 Regarding Steam Generator Tube Integrity," September 1988.

17. NUREG-1570, "Risk Assessment of Severe Accident-Induced Steam Generator Tube Rupture," March 1998.

18. NRC Meeting Minutes, "Summary of the January 8, 2009, Category 2 Public Meeting with the Nuclear Energy Institute and Industry to Discuss Steam Generator Issues," February 6, 2009; NRC ADAMS Accession No. ML090370782.

19. Westinghouse letter, LTR-SGMP-09-100-P (Proprietary) and LTR-SGMP-09-100-NP (Nonproprietary) "Response to NRC Request for Additional Information on H*; Model F and D5 Steam Generators," August 12, 2009; NRC ADAMS Accession No. ML101730391 (Nonproprietary).

20. Southern Nuclear Operating Company letter NL-09-1317, August 28, 2009, transmitting Westinghouse letter LTR-SGMP-09-104-P Attachment "White Paper on Probabilistic Assessment of H*" dated August 13, 2009; NRC ADAMS Accession No. ML092450029 (Non-Proprietary).

21. NRC letter to Wolf Creek Nuclear Operating Corporation, Wolf Creek Generating Station – "Withdrawal of License Amendment Request on Steam Generator Tube Inspections," February 28, 2008; NRC ADAMS Accession No. ML080450185.

22. Nuclear Energy Institute letter dated July 7, 2009, NRC ADAMS Accession No. ML082100086, transmitting Babcock and Wilcox Limited Canada letter 2008-06-PK-001, "Re-assessment of PMIC measurements for the determination of CTE of SA 508 Steel," dated June 6, 2008; NRC ADAMS Accession No. ML082100097.

23. Nuclear Energy Institute 97-06, Revision 3, "Steam Generator Program Guidelines," January 2011; NRC ADAMS Accession No. ML111310708.

24. Model Safety Evaluation for Plant-Specific Adoption of Technical Specifications Task Force Traveler TSTF-510, Revision 2, "Revision to Steam Generator Program Inspection Frequencies and Tube Sample Selection," Using the Consolidated Line Item Improvement Process dated October 19, 2011; NRC ADAMS Accession No. ML112101513.

25. Carolina Power and Light Company, "H. B. Robinson Steam Electric Plant, Unit 2 – Supplemental Submittal to Correct TS Pages Regarding Revision to Steam Generator Program Inspection Frequencies and Tube Sample Selection and Application of Permanent Alternate Repair Criteria," August 22, 2013.

Principal Contributor: Andrew B. Johnson

Date: August 29, 2013

August 29, 2013

Mr. William G. Gideon, Vice President
H. B. Robinson Steam Electric Plant
Carolina Power & Light Company
3581 West Entrance Road
Hartsville, SC 29550

SUBJECT: H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2 - ISSUANCE OF AN AMENDMENT TO REVISE THE STEAM GENERATOR PROGRAM INSPECTION FREQUENCIES AND TUBE SAMPLE SELECTION AND APPLICATION OF PERMANENT ALTERNATE REPAIR CRITERIA (H*) (TAC NO. ME9448)

Dear Mr. Gideon:

The Nuclear Regulatory Commission has issued the enclosed Amendment No. 235 to Renewed Facility Operating License No. DPR-23 for the H. B. Robinson Steam Electric Plant, Unit No. 2 (HBRSEP). This amendment changes the HBRSEP Technical Specifications (TSs) in response to your application dated August 29, 2012 (Agencywide Documents Access and Management System Accession No. ML12251A363), as supplemented by letters dated, March 6, 2013 (ML13072A300), April 9, 2013 (ML13123A221), and August 22, 2013.

The license amendment combines two changes that affect the same TS sections into one license amendment. The first part proposes to implement revisions consistent with TS Task Force-510, Revision 2, "Revision to Steam Generator (SG) Program Inspection Frequencies and Tube Sample Selection." The second part revises TS 5.5.9 "Steam Generator Program" to exclude portions of the SG tube below the top of the SG tubesheet from periodic inspections by implementing the permanent alternate criteria "H*."

A copy of the related Safety Evaluation is enclosed. Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,
/RA/
Siva P. Lingam, Project Manager
Plant Licensing Branch II-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-261

Enclosures:
1. Amendment No. 235 to DPR-23
2. Safety Evaluation

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ADAMS Accession No.: ML13198A367 ***Via Memo**

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