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SOUTHERN COMPANY
Energy to Serve Your World™

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U. S. Nuclear Regulatory Commission
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Vogtle Electric Generating Plant Units 1 and 2
Response to Request for Additional Information Related to
License Amendment Request to Revise Technical Specification (TS)
Sections 5.5.9, "Steam Generator (SG) Program" and TS 5.6.10,
"Steam Generator Tube Inspection Report" for Interim Alternate Repair Criterion

Ladies and Gentlemen:

On February 13, 2008, Southern Nuclear Operating Company (SNC) submitted an application to revise Vogtle Electric Generating Plant (VEGP) Technical Specification (TS) 5.5.9, "Steam Generator (SG) Program" and TS 5.6.10, "Steam Generator Tube Inspection Report," to propose a one cycle revision to incorporate an interim alternate repair criterion (ARC) in the provisions for SG tube repair criteria during Refueling Outages 1R14 (Unit 1) and 2R13 (Unit 2) and the subsequent operating cycles for each unit. The 1R14 refueling outage began on March 16, 2008.

On February 8, 2008, Wolf Creek Nuclear Operating Company (WCNOC) submitted a similar application to revise TS 5.5.9 and TS 5.6.10 to incorporate an interim ARC, and on February 20, 2008, the Nuclear Regulatory Commission (NRC) provided, by electronic mail, issues and comments related to the WCNOC amendment application. A teleconference was held with representatives from SNC, WCNOC, Exelon Generation Company, NRC and other industry representatives on February 21, 2008, to discuss the issues and comments related to the WCNOC submittal. Subsequent to this teleconference, the NRC provided WCNOC a request for additional information (RAI) letter by electronic mail on February 28, 2008 that contained thirteen (13) questions. On March 10 and 18, 2008, subsequent to the WCNOC RAI letter, the NRC provided SNC RAI letters containing seventeen (17) questions by electronic mail regarding the SNC February 13, 2008 amendment application for VEGP.

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Enclosure 1 provides the SNC responses to RAI questions 1 through 17. Enclosure 2 provides revised markups of changes to the current VEGP TS. Enclosure 3 includes the associated typed VEGP TS pages with the proposed changes incorporated. Enclosure 4 contains the proprietary Westinghouse Electric Company LLC LTR-CDME-08-043 P-Attachment, "Response to NRC Request for Additional Information Relating to LTR-CDME-08-11 P-Attachment," that provides proprietary information in response to RAI questions 6 through 17. Enclosure 5 contains the Westinghouse Electric Company LLC LTR-CDME-08-043 NP-Attachment, "Response to NRC Request for Additional Information Relating to LTR-CDME-08-11 NP-Attachment," that provides non-proprietary information in response to RAI questions 6 through 17.

As Enclosure 4 contains information proprietary to Westinghouse Electric Company LLC, it is supported by an affidavit signed by Westinghouse Electric Company LLC, the owner of the information. The affidavit sets forth the basis on which the information may be withheld from public disclosure by the Commission and addresses with specificity the considerations listed in paragraph (b)(4) of 10 CFR 2.390 of the Commission's regulations. Accordingly, it is respectfully requested that the information, which is proprietary to Westinghouse, be withheld from public disclosure in accordance with 2.390 of the Commission's regulations. This affidavit, along with Westinghouse authorization letter, CAW-08-2402, "Application for Withholding Proprietary Information from Public Disclosure," is contained in Enclosure 6.

The additional information provided in the enclosures do not impact the conclusions of the No Significant Hazards Consideration provided in the February 13, 2008 SNC application to revise TS 5.5.9 and TS 5.6.10.

SNC requests approval of the proposed license amendments by March 27, 2008 in order to support the VEGP Unit 1 spring 2008 refueling outage.

Mr. Tom E. Tynan states he is a Vice President of Southern Nuclear Operating Company, is authorized to execute this oath on behalf of Southern Nuclear Operating Company and to the best of his knowledge and belief, the facts set forth in this letter are true.

This letter contains no NRC commitments. If you have any questions, please advise.

Respectfully submitted,

SOUTHERN NUCLEAR OPERATING COMPANY

Tom E. Tynan

Tom E. Tynan
Vice President -Vogtle

Sworn to and subscribed before me this 21 *day of* March, *2008.*

Glenn D. Chandler
Notary Public

Notary Public, Burke County, Georgia
My Commission Expires January 13, 2012

My commission expires: _____

TET/DRG/sdc

Enclosures:
1. Response to Request for Additional Information
2. Revised Markups of Proposed Technical Specifications
3. Typed Pages for Technical Specifications
4. Westinghouse Electric Company LLC LTR-CDME-08-43 P-Attachment, "Response to NRC Request for Additional Information Relating to LTR-CDME-08-11 P-Attachment"
5. Westinghouse Electric Company LLC LTR-CDME-08-43 NP-Attachment, "Response to NRC Request for Additional Information Relating to LTR-CDME-08-11 NP-Attachment"
6. Westinghouse Electric Company LLC, CAW-08-2402, "Application for Withholding Proprietary Information from Public Disclosure"

cc: Southern Nuclear Operating Company
Mr. J. T. Gasser, Executive Vice President
Mr. D. H. Jones, Vice President – Engineering
RType: CVC7000

U. S. Nuclear Regulatory Commission
Mr. V. M. McCree, Acting Regional Administrator
Mr. S. P. Lingam, NRR Project Manager – Vogtle
Mr. G. J. McCoy, Senior Resident Inspector – Vogtle

Vogtle Electric Generating Plant Units 1 and 2
Response to Request for Additional Information Related to
License Amendment Request to Revise Technical Specification (TS)
Sections 5.5.9, "Steam Generator (SG) Program" and TS 5.6.10, "Steam
Generator Tube Inspection Report" for Interim Alternate Repair Criterion

Enclosure 1

Response to Request for Additional Information

Enclosure 1

Response to Request for Additional Information

By letter dated February 13, 2008 (Reference 1), Southern Nuclear Operating Company (SNC) provided to the NRC an application to revise Technical Specification (TS) 5.5.9, "Steam Generator (SG) Program" and TS 5.6.10, "Steam Generator Tube Inspection Report," to propose a one cycle revision to incorporate an interim alternate repair criterion (ARC) in the provisions for SG tube repair criteria during Refueling Outages 1R14 (Unit 1) and 2R13 (Unit 2) and the subsequent operating cycle/eddy current interval, respectively, for Units 1 and 2. On March 10 and 18, 2008, the NRC provided SNC with RAI letters containing seventeen (17) questions by electronic mail regarding the SNC February 13, 2008, amendment application for VEGP.

Provided below are responses to RAI questions 1 through 17, with supporting information regarding Questions 6 through 17 being provided in Enclosure 4.

NRC Question 1

Technical specification (TS) 5.5.9.d.3 states that if crack indications are found in any steam generator (SG) tube, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months (EFPM) or one refueling outage (whichever is less). The proposed amendment would change TS 5.5.9 d to exclude cracks in the lower 4 inches of the tubesheet from application of TS 5.5.9.d.3. The staff notes that TS 5.5.9 d.3 reflects the uniquely high detection thresholds, high measurement uncertainties, and high growth rate uncertainties that cracking generally exhibits and, therefore, is intended to ensure timely detection of cracks before tube integrity is impaired. In addition, no significant crack growth rate data exists for circumferential cracking in the tubesheet expansion. As a result, discuss your plans to modify your amendment request to remove your proposal from TS 5.5.9.d.

SNC Response

In the February 21, 2008 teleconference, the NRC stated position is that the interim ARC should only be applicable for one operating cycle and should not exclude cracks in the lower 4 inches of the tubesheet from application of TS 5.5.9.d.3. The issues provided in the February 20, 2008 electronic mail noted that the NRC position should have no consequence on planned inspections for VEGP Unit 1 fall 2009 Refueling Outage 15, if a permanent H*/B* amendment is approved before that time. Additionally, the issues indicated that the permanent H*/B* amendment can include, if necessary, a clarification that cracks in the lower 4 inches of the tubesheet found during VEGP Unit 1 spring 2008 Refueling Outage 14 (or the subsequent operating cycle) are exempted from application of TS 5.5.9.d.3.

The proposed change to TS 5.5.9.d is revised to not exclude crack indications in the lower 4 inches of the tubesheet from the application of TS 5.5.9.d.3. Additionally, the proposed change is revised to not include the editorial change regarding previously elapsed single-cycle TS amendments. The response to

Enclosure 1

Response to Request for Additional Information

Question 11 in Enclosure 4 provides additional information regarding the tube end weld criteria.

The originally proposed changes to TS 5.5.9.d, as discussed in Reference 1, are noted in strikethrough text and italic type as follows:

d. "Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube repair criteria. ~~*For Unit 2 during Refueling Outage 11 and the subsequent operating cycle, the portion of the tube below 17 inches from the top of the hot leg tubesheet is excluded*~~ For Unit 1 during Refueling Outage 13 and the subsequent operating cycle, and for Unit 2 during Refueling Outage 12 and the subsequent operating cycle, the portion of the tube below 17 inches from the top of the hot leg tubesheet is excluded. *For Unit 2 during Refueling Outage 13 and the 36-month eddy current inspection interval, SGs in which the portion of the tube below 17 inches from the top of the tubesheet has no greater than 183 degree circumferential service-induced crack-like flaws are excluded from the requirements of Paragraph 3 below.* The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements of d.1, d.2, and d.3 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. An assessment of degradation shall be performed to determine the type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations."

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

2. Inspect 100% of the tubes at sequential periods of 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.

3. If crack indications are found in any SG tube, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months

or one refueling outage (whichever is less). If definitive information, such as from examination of a pulled tube, diagnostic nondestructive 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.

Since this criterion would no longer involve revision to TS 5.5.9.d, there are no proposed changes to TS 5.5.9.d. TS 5.5.9.d is restated below for completeness purposes; underlined text indicates revisions to the proposed changes in the February 13 submittal which are reflected in this letter:

d. "Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube repair criteria. <u>For Unit 2 during Refueling Outage 11 and the subsequent operating cycle, the portion of the tube below 17 inches from the top of the hot leg tubesheet is excluded.</u> For Unit 1 during Refueling Outage 13 and the subsequent operating cycle, and for Unit 2 during Refueling Outage 12 and the subsequent operating cycle, the portion of the tube below 17 inches from the top of the hot leg tubesheet is excluded. ~~*For Unit 2 during Refueling Outage 13 and the 36-month eddy current inspection interval, SGs in which the portion of the tube below 17 inches from the top of the tubesheet has no greater than 183 degree circumferential service-induced crack-like flaws are excluded from the requirements of Paragraph 3 below.*~~ The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements of d.1, d.2, and d.3 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. An assessment of degradation shall be performed to determine the type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations."

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

2. Inspect 100% of the tubes at sequential periods of 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.

3. If crack indications are found in any SG tube, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever is less). If definitive information, such as from examination of a pulled tube, diagnostic nondestructive 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.

Enclosure 2 provides revised TS 5.5.9 pages and supersedes the proposed changes in Enclosure 2 of Reference 1.

NRC Question 2

For the same reasons as cited above, discuss your plans to modify TS 5.5.9.c.3 to eliminate the proposed alternate repair criteria (ARC) applicable to a 36-month eddy current inspection interval. In addition, discuss your plans to modify the following clauses: "and subsequent 18-month eddy current inspection interval," "and subsequent 36-month eddy current inspection interval," and, "and subsequent 18-month and 36-month eddy current inspection intervals." with the following, "and the subsequent operating cycle." Similarly, discuss your plans for modifying the parenthetical expressions, "(and any inspections performed in the subsequent-18 month inspection interval or 36-month inspection interval)," in proposed new reporting requirements in TS 5.6.10.h, i, and j with the following: "and any inspections performed in the subsequent operating cycle."

SNC Response

In the February 21, 2008 teleconference, the NRC position stated that the interim ARC should only be applicable for one operating cycle. The proposed changes to TS 5.5.9.c. and TS 5.6.10 are for one operating cycle. Use of "operating cycle" is consistent with previously approved one-cycle amendments for SNC. Additionally, during the teleconference on February 21, 2008, the NRC specifically indicated that the Technical Specifications should be revised to address multiple circumferential flaws in the bottom 4 inches of the tube and the tube end weld. Also, during the teleconference on March 14, 2008, the NRC indicated that Interim ARC requirements for inspections conducted in the current timeframe should change in the future due to technology development. Therefore, TS 5.5.9.c.3 is revised to address multiple circumferential flaws and to remove ARC provisions with respect to VEGP Unit 2 Refueling Outage 13 and the subsequent operating cycle. The responses to Questions 10 and 11 in Enclosure 4 provide additional information regarding the tube end weld criteria.

The originally proposed changes to TS 5.5.9.c, as discussed in Reference 1, are noted in italic type as follows:

c. Provisions for SG tube repair criteria. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged.

The following alternate tube repair criteria *shall* be applied as an alternative to the 40% depth-based criteria:

1. *For Unit 1 during Refueling Outage 13 and the subsequent operating cycle, and for Unit 2 during Refueling Outage 12 and the subsequent operating cycle, degradation identified in the portion of the tube below 17 inches from the top of the hot leg tubesheet does not require plugging.*

   For Unit 1 during Refueling Outage 13 and the subsequent operating cycle, and for Unit 2 during Refueling Outage 12 and the subsequent operating cycle, degradation identified in the portion of the tube from the top of the hot leg tubesheet to 17 inches below the top of the hot leg tubesheet shall be plugged upon detection.

2. *For Unit 1 during Refueling Outage 14 and the subsequent operating cycle, tubes with less than or equal to a 214 degree circumferential service-induced crack-like flaw found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging. Tubes with greater than a 214 degree circumferential service-induced crack-like flaw found in the portion of the tube below 17 inches from the top of the tubesheet shall be removed from service. Tubes with service-induced crack-like flaws located within the region from the top of the tubesheet to 17 inches below the top of the tubesheet shall be removed from service. Tubes with service-induced axial cracks found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging.*

3. *For Unit 2 Refueling Outage 13 and subsequent 18-month eddy current inspection interval, tubes with less than or equal to a 214 degree circumferential service-induced crack-like flaw found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging. Tubes with greater than a 214 degree circumferential service-induced crack-like flaw found in the portion of the tube below 17 inches from the top of the tubesheet shall be removed from service.*

   For Unit 2 Refueling Outage 13 and subsequent 36-month eddy current inspection interval, tubes with less than or equal to a

183 degree circumferential service-induced crack-like flaw found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging. Tubes with greater than a 183 degree circumferential service-induced crack-like flaw found in the portion of the tube below 17 inches from the top of the tubesheet shall be removed from service.

For Unit 2 Refueling Outage 13 and subsequent 18-month and 36-month eddy current inspection intervals, tubes with service-induced crack-like flaws located within the region from the top of the tubesheet to 17 inches below the top of the tubesheet shall be removed from service. Tubes with service-induced axial cracks found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging.

This criterion would be revised as follows in response to the NRC Question 2 and to add provisions with respect to multiple flaws in the bottom 4 inches of the tubesheet as noted in underlined text (revisions to the proposed TS changes reflected in this letter), strikethrough text (text proposed for deletion in the proposed TS amendment), and italic type (text proposed for addition in the proposed TS amendment); additionally, the proposed change is revised to not include the editorial change regarding previously elapsed single-cycle TS amendments. :

c. Provisions for SG tube repair criteria. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged.

   The following alternate tube repair criteria *shall* be applied as an alternative to the 40% depth-based criteria:

   1. <u>For Unit 2 during Refueling Outage 11 and the subsequent operating cycle, degradation found in the portion of the tube below 17 inches from the top of the hot leg tubesheet does not require plugging.</u>

      <u>For Unit 2 during Refueling Outage 11 and the subsequent operating cycle, degradation identified in the portion of the tube from the top of the hot leg tubesheet to 17 inches below the top of the tubesheet shall be plugged upon detection.</u>

   2. For <u>Unit 1 during Refueling Outage 13 and the subsequent operating cycle, and for</u> Unit 2 during Refueling Outage 12 and the subsequent operating cycle, degradation identified in the portion of the tube below 17 inches from the top of the hot leg tubesheet does not require plugging.

For Unit 1 during Refueling Outage 13 and the subsequent operating cycle, and for Unit 2 during Refueling Outage 12 and the subsequent operating cycle, degradation identified in the portion of the tube from the top of the hot leg tubesheet to 17 inches below the top of the hot leg tubesheet shall be plugged upon detection.

3. *For Unit 1 during Refueling Outage 14 and the subsequent operating cycle, tubes with flaws having a circumferential component less than or equal to 203 ~~a 214~~ degrees ~~circumferential service-induced crack-like flaw~~ found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet do not require plugging. Tubes with flaws having a circumferential component greater than 203~~a 214~~ degrees ~~circumferential service-induced crack-like flaw~~ found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet shall be removed from service.*

   Tubes with service-induced ~~crack-like~~ flaws located within the region from the top of the tubesheet to 17 inches below the top of the tubesheet shall be removed from service. Tubes with service-induced axial cracks found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging.

   When more than one flaw with circumferential components is found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet with the total of the circumferential components greater than 203 degrees and an axial separation distance of less than 1 inch, then the tube shall be removed from service. When the circumferential components of each of the flaws are added, it is acceptable to count the overlapped portions only once in the total of circumferential components.

   When one or more flaws with circumferential components are found in the portion of the tube within 1 inch from the bottom of the tubesheet and the total of the circumferential components found in the tube exceeds 94 degrees, then the tube shall be removed from service. When one or more flaws with circumferential components are found in the portion of the tube within 1 inch from the bottom of the tubesheet, and within 1 inch axial separation distance of a flaw above 1 inch from the bottom of the tubesheet, and the total of the circumferential components found in the tube exceeds 94 degrees, then the tube shall be removed from service. When the circumferential components of each of the flaws are added, it is acceptable to

count the overlapped portions only once in the total of circumferential components.

~~*3. For Unit 2 Refueling Outage 13 and subsequent 18-month eddy current inspection interval, tubes with less than or equal to a 214 degree circumferential service-induced crack-like flaw found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging. Tubes with greater than a 214 degree circumferential service-induced crack-like flaw found in the portion of the tube below 17 inches from the top of the tubesheet shall be removed from service.*~~

~~*For Unit 2 Refueling Outage 13 and subsequent 36-month eddy current inspection interval, tubes with less than or equal to a 183 degree circumferential service-induced crack-like flaw found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging. Tubes with greater than a 183 degree circumferential service-induced crack-like flaw found in the portion of the tube below 17 inches from the top of the tubesheet shall be removed from service.*~~

~~*For Unit 2 Refueling Outage 13 and subsequent 18-month and 36-month eddy current inspection intervals, tubes with service-induced crack-like flaws located within the region from the top of the tubesheet to 17 inches below the top of the tubesheet shall be removed from service. Tubes with service-induced axial cracks found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging.*~~

Proposed changes to TS 5.6.10, as discussed in Reference 1, are noted in strikethrough text and italic type as follows:

"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 results of tube pulls and in-situ testing~~.~~*;*

h. Following completion of a Unit 1 inspection performed in Refueling Outage 14 (and any inspections performed in the subsequent operating cycle) and following completion of a Unit 2 inspection performed in Refueling Outage 13 (and any inspections performed in the subsequent 18-month inspection interval or 36-month inspection interval), the number of indications and location, size, orientation, and whether initiated on primary or secondary side for each service-induced crack-like flaw within the thickness of the tubesheet;

i. Following completion of a Unit 1 inspection performed in Refueling Outage 14 (and any inspections performed in the subsequent operating cycle) and following completion of a Unit 2 inspection performed in Refueling Outage 13 (and any inspections performed in the subsequent 18-month inspection interval or 36-month inspection interval), the primary to secondary LEAKAGE rate observed in each SG (if it is not practical to assign 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 which is the subject of the report; and

j. Following completion of a Unit 1 inspection performed in Refueling Outage 14 (and any inspections performed in the subsequent operating cycle) and following completion of a Unit 2 inspection performed in Refueling Outage 13 (and any inspections performed in the subsequent 18-month inspection interval or 36-month inspection interval), the calculated accident leakage rate from the portion of the tube 17 inches below the top of the tubesheet for the most limiting accident in the most limiting SG."

The reporting criteria would be revised as follows in response to the NRC Question 2 and to add provisions with respect to multiple flaws in the bottom 4 inches of the tubesheet, as noted in underlined, text, strikethrough text and italic type:

"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; and

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

h. Following completion of a Unit 1 inspection performed in Refueling Outage 14 (and any inspections performed in the subsequent operating cycle) ~~) and following completion of a Unit 2 inspection performed in Refueling Outage 13 (and any inspections performed in the subsequent 18-month inspection interval or 36-month inspection interval)~~, the number of indications and location, size, orientation, ~~and~~ whether initiated on primary or secondary side for each service-induced flaw within the thickness of the tubesheet, and the total of the circumferential components and any circumferential overlap below 17 inches from the top of the tubesheet as determined in accordance with TS 5.5.9.c.3;

i. Following completion of a Unit 1 inspection performed in Refueling Outage 14 (and any inspections performed in the subsequent operating cycle)~~ and following completion of a Unit 2 inspection performed in Refueling Outage 13 (and any inspections performed in the subsequent 18-month inspection interval or 36-month inspection interval)~~, the primary to secondary LEAKAGE rate observed in each SG (if it is not practical to assign 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 which is the subject of the report; and

j. Following completion of a Unit 1 inspection performed in Refueling Outage 14 (and any inspections performed in the subsequent operating cycle) ~~) and following completion of a Unit 2 inspection performed in Refueling Outage 13 (and any inspections performed in the subsequent 18-month inspection interval or 36-month inspection interval)~~, the calculated accident leakage rate from the portion of the tube below 17 inches from~~below~~ the top of the tubesheet for the most limiting accident in the most limiting SG."

Enclosure 2 provides revised TS 5.5.9 pages and supersedes the proposed changes in Enclosure 2 of Reference 1.

NRC Question 3

Given that the ability of eddy current to size cracks in the weld has not been demonstrated, justify the position in the amendment request that visual inspection of the weld will not be performed unless the eddy current results indicate that a weld flaw is greater than the weld crack acceptance criteria.

SNC Response

A teleconference was held with representatives from Southern Nuclear Operating Company, WCNOC, Exelon Generation Company, NRC and other industry representatives on March 14, 2008, which included discussing the recent results of the peer review evaluation related to the Catawba Unit 2 cold leg tube end indications discovered in 2007. The results of the peer review were presented to other members of the NRC on March 13, 2008.

Data from ten Catawba tubes was included in the evaluation. In addition, a tubesheet mockup was used to evaluate the capability of eddy current testing (ECT) to discriminate the tube end from the weld. The mockup contained eight tubes that were fully expanded into a full depth tubesheet with cladding and autogenous welds. Notches were placed using electro-discharge machining (EDM) in two of the mockup tubes. The notches were both axial and circumferential. Rotating coil and X-Probe data were collected. The ECT coil sensing field integrated the approaching tube end exit signal and weld area simultaneously. Based upon physical geometry, there is a limited axial component of the weld (approximately 0.020") offering limited opportunity for detection. The Catawba signals were large in terms of amplitude compared to the mockup flaws. Since ECT does not discern the weld material from the tube material, identification of the tube end is approximate. All Catawba indications were far enough from the tube end to conclude that they were above the probable location of the weld. ECT detection is not optimum within the weld, based on the 40% circumferential EDM notch reviewed in the mockup.

Utilizing the above information, cracking exclusively in the tube end weld is not considered a potential damage mechanism for the purposes of the Degradation Assessment. This is appropriate since there were no reported instances of cracks only in the weld. Primary water stress corrosion cracking (PWSCC) will continue to be considered a potential damage mechanism for the portion of the tube within the tubesheet.

In discussion with the NRC, it was determined for the portion of the tube 1" from the bottom of the tubesheet, flaws having a circumferential component of greater than the calculated value (subsequently determined to be 94 degrees) should be

removed from service and that a visual inspection of the tube end weld would not be required. As such, TS 5.5.9.c.3 is revised to reflect this position and the commitments in Reference 1 concerning the performance of visual inspections are withdrawn.

NRC Question 4

Please discuss your plans to modify the proposed application of the ARC from circumferential, service induced, crack-like flaws to the circumferential component of flaws in general. An example of an acceptable approach is to replace the proposed words, "tubes with less than or equal to a 214 degree circumferential service-induced crack-like flaw...," with the words, "tubes with service induced flaws having a circumferential component less than or equal to 214 degrees...".

SNC Response

The proposed wording for the portion of the tube below 17 inches from the top of the tubesheet has been revised to reflect the wording "flaws having a circumferential component." See the revised TS wording in the response to NRC Question 2 above. In a teleconference with the NRC on March 5, 2008, the NRC questioned the use of "service-induced crack-like flaws" for the portion of the tube from the top of the tubesheet to 17 inches below the top of the tubesheet. Use of this wording was maintained based on the discussion at the July 11, 2007 meeting and the response to RAI question 34 in Wolf Creek Nuclear Operating Company letter ET 07-0043, "Response to Request for Additional Information Related to License Amendment Request to Revise the Steam Generator Program," dated September 27, 2007. From the March 5, 2008 teleconference, it was agreed to remove "crack-like" from the proposed wording in TS 5.5.9.c.3 and TS 5.6.10.h.

NRC Question 5

An improved inspection technique (e.g., visual, eddy current) capable of reliably detecting cracks in the weld that may challenge the applicable acceptance limit may be needed to support future interim amendment requests following spring 2008. (This position becomes moot if an H/B* amendment is approved in the meantime.) For this reason, please discuss your plans to revise the amendment request to apply only to Vogtle Unit 1 during Refueling Outage 14 and the subsequent operating cycle.*

SNC Response

The originally proposed change to TS 5.5.9.c is revised to only apply to requirements for Unit 1 Refueling Outage 14 and subsequent operating cycle.

The originally proposed changes to TS 5.5.9 for Unit 2 interim ARC provisions are deleted from the amendment request. The proposed change to TS 5.6.10 is revised to propose changes to requirements for Unit 1 Refueling Outage 14 and subsequent operating cycle.

These revisions to the proposed changes are illustrated in the SNC responses to NRC RAI Questions 1 (TS 5.5.9.d), 2 (TS 5.5.9.c), and 3 (TS 5.6.10).

NRC Question 6

Figure 3-7 (LTR-CDME-08-11 P) needs to provide all geometry details assumed in the weld analysis on pages 7, 9 and 10. (The staff does not understand the assumed weld geometry based on the discussion on pages 7, 9 and 10.) With respect to the equation for S.A. near the top of page 10, what is the parameter whose value is 0.020 and what is the solution for "y"?

SNC Response

The Question 6 response in Westinghouse LTR-CDME-08-43 (Enclosure 4) provides the response to this question.

NRC Question 7

On page 10, the assumed flaw is said to extend a distance "d" into this "surface." Does "surface" refer to the outer ellipse or inner ellipse in Figure 3-5? Figure 3-5 suggests it is from the inner ellipse.

SNC Response

The Question 7 response in Westinghouse LTR-CDME-08-43 (Enclosure 4) provides the response to this question.

NRC Question 8

What was the assumed flow stress for the weld material? What was the basis for selecting this value?

SNC Response

The Question 8 response in Westinghouse LTR-CDME-08-43 (Enclosure 4) provides the response to this question.

NRC Question 9

LTR-CDME-05-P states that the tube to tubesheet welds were designed and analyzed as primary pressure boundary in accordance with the requirements of Section III of the ASME Code. Please provide a summary of the Code analysis, including the calculated maximum stress and applicable Code stress limit.

SNC Response

The Question 9 response in Westinghouse LTR-CDME-08-43 (Enclosure 4) provides the response to this question regarding information previously transmitted for Vogtle in Westinghouse document WCAP-16794-P.

NRC Question 10

Regarding the weld repair criterion:

A detailed stress analysis (e.g., finite element) would be expected to reveal a much more complex stress state than that assumed in the licensee's analysis, which may impact the likely locations for crack initiation and direction of crack propagation. In addition, the dominant stresses for crack initiation and crack growth may involve residual stresses in addition to operational stresses. Thus, the 35-degree conical "plane" is not the only plane within which cracks may initiate and grow.

One hypothetical crack plane, which appears more limiting than the one assumed by the licensee, is the cylindrical "plane" defined by the expanded tube outer diameter where the weld is in a state of shear. The staff estimates that the required circumferential ligament to resist an end cap load of 1863 lb is greater than 180 degrees (without allowances). Please address these concerns and provide a detailed justification for why the submitted analysis is conservative.

SNC Response

The Question 10 response in Westinghouse LTR-CDME-08-43 (Enclosure 4) provides the response to this question.

NRC Question 11

The proposed tube and weld repair criteria do not address interaction effects of multiple circumferential flaws that may be in close proximity (e.g., axial separation of one or two tube diameters). Please address this concern and identify any revisions which may be needed to the alternate tube repair criteria and the maximum acceptable weld flaw size.

SNC Response

The Question 11 response in Westinghouse LTR-CDME-08-43 (Enclosure 4) provides the response to this question.

NRC Question 12

The technical support document for the interim ARC amendment does not make it clear how licensees will ensure they satisfy the accident induced leakage performance criteria. Please describe the methodology to be used to ensure the accident induced leakage performance criteria is met. Include in this response (a) how leakage from sources other than the lower 4-inches of the tube will be addressed (in the context of ensuring the performance criteria is met), and (b) how leakage from flaws (if any) in the lower 4 inches of the tube will be determined (e.g., determining the leakage from each flaw; multiplying the normal operating leak rate by a specific factor).

SNC Response

The Question 12 response in Westinghouse LTR-CDME-08-43 (Enclosure 4) provides the response to this question. The calculation in the Enclosure 4 Question 12 response bounds the Vogtle Design Basis Accident values, therefore, the methodology described in the response is conservative with respect to Vogtle Unit 1.

NRC Question 13

The proposed "modified B" approach relies to some extent on an assumed, constant value of loss coefficient, based on a lower bound of the data. This contrasts with the "nominal B*" approach which, in its latest form (as we understand it) is not directly impacted by the assumed value of loss coefficient since this value is assumed to be constant with increasing contact pressure between the tube and tubesheet. Given the amount of time for the staff to review the interim ARC, the staff will not be able to make a conclusion as to whether the assumed value of loss coefficient in the "modified B*" approach is conservative. However, the staff has performed some evaluations regarding the potential for the normal operating leak rate to increase under steam line break conditions using various values of (l_{NOP}/ l_{SLB}) determined from the "nominal B*" approach (which does not rely on an assumed value of loss coefficient). With these analyses and recognizing the issues associated with some of these previous H*/B* analyses, it would appear that a factor of 2.5 reasonably bounds the potential increase in leakage that would be realized in going from normal operating to steam line break conditions. Please discuss your plans to modify your proposal to indicate that the leak rate during normal operation (for flaws in the lower 4-inches of tube) will increase by a factor of 2.5 under steam line break conditions.*

SNC Response

The Question 13 response in Westinghouse LTR-CDME-08-43 (Enclosure 4) provides the response to this question. The calculation in the Enclosure 4 Question 13 response is conservative with respect to Vogtle Design Basis Accident leakage values; the DBA Leak Margin Available value reflects conservatism with respect to ensuring compliance with the Accident Induced Leakage performance criterion.

NRC Question 14

The mathematical constant π has been omitted from the first term of the equation near the top of page 8 and the equation at the bottom of page 8. It is not clear if this is a typographical error, or if π has been purposely omitted. If the omission is intentional, please explain.

SNC Response

The Question 14 response in Westinghouse LTR-CDME-08-43 (Enclosure 4) provides the response to this question.

NRC Question 15

The last term of the equation at the bottom of page 8 includes the parenthetical $(r_o^2 + r_i^2)$. The staff believes this should be $(r_o^2 - r_i^2)$. It is not clear if this is a typographical error, or if the radii are intentionally being summed. If intentional, please explain why the squared radii should be summed and not subtracted.

SNC Response

The Question 15 response in Westinghouse LTR-CDME-08-43 (Enclosure 4) provides the response to this question.

NRC Question 16

Explain why it is necessary to subtract A_f (area of the flaw) from S.A. (surface area of the frustum) in the first term of the force balance equation on page 10. (The staff believes this term should be deleted.).

SNC Response

The Question 16 response in Westinghouse LTR-CDME-08-43 (Enclosure 4) provides the response to this question.

NRC Question 17

Explain the use of the mathematical constant P_i (internal pressure) rather than P (3ΔP or 4800 psi) in the equations on pages 8 and 10. The explanation on page 11 is not sufficient and appears to the staff to be incorrect.

[The staff makes two observations here in response to possible industry concerns regarding Item 12.

First, the staff acknowledges that the ratio of the allowed accident leakage and the operational leakage is 2.5 for Wolf Creek, which is equal to the factor of 2.5 above, while the ratio is 3.5 for Vogtle and 5 for Byron/Braidwood). This is not an atypical situation as is discussed in NRC RIS 2007-20. The operational leakage limit in the technical specifications can never be assumed to ensure that accident leakage will be within what is assumed in the accident analysis, even if the technical specification limit is zero. For example, part through wall flaws in the free span which are not leaking under normal operating conditions may pop through wall and leak under accident conditions. For cracks in the free span which are leaking under normal operating conditions, the ratio of SLB leakage to normal operating leakage can be substantially greater than 2.5 depending on the length of the crack. It is the licensee's responsibility to ensure that the accident leakage limits are met through implementation of an effective SG program, including an engineering assessment of any operational leakage that may occur in terms of its implications for leakage under accident conditions (based on considerations such as past inspection results and operational assessments, experience at similar plants, etc.).

Second, the staff is not aware of any operational leakage to date from the tubesheet region for the subject class of plants, and there seems little reason to expect that this situation will change significantly in the next 18 months. Thus, the NRC staff's approach discussed above is not expected to have any significant impact for the licensees requesting relief from the tube repair criteria in the lower 4-inches of the tube.]

SNC Response

The Question 17 response in LTR-CDME-08-43 (Enclosure 4) provides the response to this question. Regarding the two observations, related information is provided in the response to Question 12.

References:

1. SNC letter NL-08-0148, "License Amendment Request to Revise Technical Specification (TS) Sections 5.5.9, "Steam Generator (SG) Program" and TS 5.6.10, "Steam Generator Tube Inspection Report" for Interim Alternate Repair Criterion," February 13, 2008

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Enclosure 2

Revised Markups of Proposed Technical Specifications

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

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 1 gpm per SG.

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

c. Provisions for SG tube repair criteria. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged.

The following alternate tube repair criteria ~~may~~shall be applied as an alternative to the 40% depth based criteria:

1. For Unit 2 during Refueling Outage 11 and the subsequent operating cycle, degradation found in the portion of the tube below 17 inches from the top of the hot leg tubesheet does not require plugging.

   For Unit 2 during Refueling Outage 11 and the subsequent operating cycle, degradation identified in the portion of the tube from the top of the hot leg tubesheet to 17 inches below the top of the tubesheet shall be plugged upon detection.

2. For Unit 1 during Refueling Outage 13 and the subsequent operating cycle, and for Unit 2 during Refueling Outage 12 and the subsequent operating cycle, degradation identified in the portion of the tube below 17 inches from the top of the hot leg tubesheet does not require plugging.

   For Unit 1 during Refueling Outage 13 and the subsequent operating cycle, and for Unit 2 during Refueling Outage 12 and the subsequent operating cycle, degradation identified in the portion of the tube from the top of the hot leg tubesheet to 17 inches below the top of the hot leg tubesheet shall be plugged upon detection.

Insert for TS Page 5.5-8

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

(continued)

Insert for TS page 5.5-8:

3. For Unit 1 during Refueling Outage 14 and the subsequent operating cycle, tubes with flaws having a circumferential component less than or equal to 203 degrees found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet do not require plugging. Tubes with flaws having a circumferential component greater than 203 degrees found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet shall be removed from service.

   Tubes with service-induced flaws located within the region from the top of the tubesheet to 17 inches below the top of the tubesheet shall be removed from service. Tubes with service-induced axial cracks found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging.

   When more than one flaw with circumferential components is found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet with the total of the circumferential components greater than 203 degrees and an axial separation distance of less than 1 inch, then the tube shall be removed from service. When the circumferential components of each of the flaws are added, it is acceptable to count the overlapped portions only once in the total of circumferential components.

   When one or more flaws with circumferential components are found in the portion of the tube within 1 inch from the bottom of the tubesheet, and the total of the circumferential components found in the tube exceeds 94 degrees, then the tube shall be removed from service. When one or more flaws with circumferential components are found in the portion of the tube within 1 inch from the bottom of the tubesheet, and within 1 inch axial separation distance of a flaw above 1 inch from the bottom of the tubesheet, and the total of the circumferential components found in the tube exceeds 94 degrees, then the tube shall be removed from service. When the circumferential components of each of the flaws are added, it is acceptable to count the overlapped portions only once in the total of circumferential components.

5.6 Reporting Requirements

5.6.9 Deleted.

5.6.10 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. 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~~;~~.

Insert for TS Page 5.6-6

Insert for TS page 5.6-6:

h. Following completion of a Unit 1 inspection performed in Refueling Outage 14 (and any inspections performed in the subsequent operating cycle), the number of indications and location, size, orientation, whether initiated on primary or secondary side for each service-induced flaw within the thickness of the tubesheet, and the total of the circumferential components and any circumferential overlap below 17 inches from the top of the tubesheet as determined in accordance with TS 5.5.9.c.3;

i. Following completion of a Unit 1 inspection performed in Refueling Outage 14 (and any inspections performed in the subsequent operating cycle), the primary to secondary LEAKAGE rate observed in each SG (if it is not practical to assign 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 which is the subject of the report; and

j. Following completion of a Unit 1 inspection performed in Refueling Outage 14 (and any inspections performed in the subsequent operating cycle), the calculated accident leakage rate from the portion of the tube below 17 inches from the top of the tubesheet for the most limiting accident in the most limiting SG.

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Enclosure 3

Typed Pages for Technical Specifications

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

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 1 gpm per SG.

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

c. Provisions for SG tube repair criteria. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged.

The following alternate tube repair criteria shall be applied as an alternative to the 40% depth based criteria:

1. For Unit 2 during Refueling Outage 11 and the subsequent operating cycle, degradation found in the portion of the tube below 17 inches from the top of the hot leg tubesheet does not require plugging.

   For Unit 2 during Refueling Outage 11 and the subsequent operating cycle, degradation identified in the portion of the tube from the top of the hot leg tubesheet to 17 inches below the top of the tubesheet shall be plugged upon detection.

2. For Unit 1 during Refueling Outage 13 and the subsequent operating cycle, and for Unit 2 during Refueling Outage 12 and the subsequent operating cycle, degradation identified in the portion of the tube below 17 inches from the top of the hot leg tubesheet does not require plugging.

   For Unit 1 during Refueling Outage 13 and the subsequent operating cycle, and for Unit 2 during Refueling Outage 12 and the subsequent operating cycle, degradation identified in the portion of the tube from the top of the hot leg tubesheet to 17 inches below the top of the hot leg tubesheet shall be plugged upon detection.

3. For Unit 1 during Refueling Outage 14 and the subsequent operating cycle, tubes with flaws having a circumferential component less than or equal to 203 degrees found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet do not require plugging. Tubes with flaws having a

(continued)

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

circumferential component greater than 203 degrees found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet shall be removed from service.

Tubes with service-induced flaws located within the region from the top of the tubesheet to 17 inches below the top of the tubesheet shall be removed from service. Tubes with service-induced axial cracks found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging.

When more than one flaw with circumferential components is found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet with the total of the circumferential components greater than 203 degrees and an axial separation distance of less than 1 inch, then the tube shall be removed from service. When the circumferential components of each of the flaws are added, it is acceptable to count the overlapped portions only once in the total of circumferential components.

When one or more flaws with circumferential components are found in the portion of the tube within 1 inch from the bottom of the tubesheet, and the total of the circumferential components found in the tube exceeds 94 degrees, then the tube shall be removed from service. When one or more flaws with circumferential components are found in the portion of the tube within 1 inch from the bottom of the tubesheet, and within 1 inch axial separation distance of a flaw above 1 inch from the bottom of the tubesheet, and the total of the circumferential components found in the tube exceeds 94 degrees, then the tube shall be removed from service. When the circumferential components of each of the flaws are added, it is acceptable to count the overlapped portions only once in the total of circumferential components.

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube repair criteria. For Unit 2 during Refueling Outage 11 and the subsequent operating cycle, the portion of the tube below 17 inches from the top of the hot leg tubesheet is excluded. For Unit 1 during Refueling Outage 13 and the subsequent operating cycle,

(continued)

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

and for Unit 2 during Refueling Outage 12 and the subsequent operating cycle, the portion of the tube below 17 inches from the top of the hot leg tubesheet is excluded. The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements of d.1, d.2, and d.3 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. An assessment of degradation shall be performed to determine the type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

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

2. Inspect 100% of the tubes at sequential periods of 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.

3. If crack indications are found in any SG tube, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever is less). If definitive information, such as from examination of a pulled tube, diagnostic nondestructive 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 a sampling schedule for the critical variables and control points for these variables;

(continued)

5.5 Programs and Manuals

5.5.10 Secondary Water Chemistry Program (continued)

b. Identification of the procedures used to measure the values of the critical variables;

c. Identification of process sampling points;

d. Procedures for the recording and management of data;

e. Procedures defining corrective actions for all off control point chemistry conditions; and

f. A procedure identifying the authority responsible for the interpretation of the data and the sequence and timing of administrative events, which is required to initiate corrective action.

5.5.11 Ventilation Filter Testing Program (VFTP)

A program shall be established to implement the following required testing of Engineered Safety Feature (ESF) filter ventilation systems at the frequencies specified in accordance with Regulatory Guide 1.52, Revision 2, and ASME N510-1980:

a. Demonstrate for each of the ESF systems that an inplace test of the high efficiency particulate air (HEPA) filters shows a penetration and system bypass ≤ 0.05% when tested in accordance with Regulatory Guide 1.52, Revision 2, and ASME N510-1980 at the system flow rate specified below ± 10%.

ESF Ventilation System	Flow Rate
Control Room Emergency Filtration System (CREFS)	19,000 CFM
Piping Penetration Area Filtration and Exhaust (PPAFES)	15,500 CFM

b. Demonstrate for each of the ESF systems that an inplace test of the charcoal adsorber shows a penetration and system bypass ≤ 0.05% when tested in accordance with Regulatory Guide 1.52, Revision 2, and ASME N510-1980 at the system flow rate specified below ± 10%.

(continued)

5.5 Programs and Manuals

5.5.11 Ventilation Filter Testing Program (VFTP) (continued)

ESF Ventilation System	Flow Rate
CREFS	19,000 CFM
PPAFES	15,500 CFM

c. Demonstrate for each of the ESF systems that a laboratory test of a sample of the charcoal adsorber, when obtained as described in Regulatory Guide 1.52, Revision 2, shows the methyl iodide penetration less than or equal to the value specified below when tested in accordance with ASTM D3803-1989 at a temperature of 30°C and greater than or equal to the relative humidity specified below.

ESF Ventilation System	Penetration	RH
CREFS	.2%	70%
PPAFES	10%	95%

d. Demonstrate for each of the ESF systems that the pressure drop across the combined HEPA filters, the charcoal adsorbers, and CREFS cooling coils is less than the value specified below when tested in accordance with Regulatory Guide 1.52, Revision 2, and ASME N510-1989 at the system flow rate specified below ± 10%.

ESF Ventilation System	Delta P	Flow Rate
CREFS	7.1 in. water gauge	19,000 CFM
PPAFES	6 in. water gauge	15,500 CFM

e. Demonstrate that the heaters for the CREFS dissipate ≥ 95 kW when corrected to 460 V when tested in accordance with ASME N510-1989.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the VFTP test frequencies.

5.5.12 Explosive Gas and Storage Tank Radioactivity Monitoring Program

This program provides controls for potentially explosive gas mixtures contained in the Gaseous Waste Processing System, the quantity of radioactivity contained in each Gas Decay Tank, and the quantity of radioactivity contained in

(continued)

5.5 Programs and Manuals

5.5.12 Explosive Gas and Storage Tank Radioactivity Monitoring Program (continued)

unprotected outdoor liquid storage tanks. The gaseous radioactivity quantities shall be determined following the methodology in Branch Technical Position (BTP) ETSB 11-5, "Postulated Radioactive Release due to Waste Gas System Leak or Failure." The liquid radwaste quantities shall be limited to 10 curies per outdoor tank in accordance with Standard Review Plan, Section 15.7.3, "Postulated Radioactive Release due to Tank Failures."

The program shall include:

a. The limits for concentrations of hydrogen and oxygen in the Gaseous Waste Processing System and a surveillance program to ensure the limits are maintained. Such limits shall be appropriate to the system's design criteria (i.e., whether or not the system is designed to withstand a hydrogen explosion);

b. A surveillance program to ensure that the quantity of radioactivity contained in each gas decay tank is less than the amount that would result in a whole body exposure of ≥ 0.5 rem to any individual in an unrestricted area, in the event of an uncontrolled release of the tanks' contents; and

c. A surveillance program to ensure that the quantity of radioactivity contained in all outdoor liquid radwaste tanks that are not surrounded by liners, dikes, or walls, capable of holding the tanks' contents and that do not have tank overflows and surrounding area drains connected to the Liquid Radwaste Treatment System is limited to ≤ 10 curies per tank, excluding tritium and dissolved or entrained noble gases. This surveillance program provides assurance that in the event of an uncontrolled release of the tank's contents, the resulting concentrations would be less than the limits of 10 CFR 20, Appendix B, Table 2, Column 2, at the nearest potable water supply and the nearest surface water supply in an unrestricted area.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Explosive Gas and Storage Tank Radioactivity Monitoring Program surveillance frequencies.

5.5.13 Diesel Fuel Oil Testing Program

A diesel fuel oil testing program to implement required testing of both new fuel oil and stored fuel oil shall be established. The program shall include sampling and testing requirements, and acceptance criteria, all in accordance with applicable ASTM Standards. The purpose of the program is to establish the following:

a. Acceptability of new fuel oil for use prior to addition to storage tanks by determining that the fuel oil has:

(continued)

5.5 Programs and Manuals

5.5.13 Diesel Fuel Oil Testing Program (continued)

1. an API gravity or an absolute specific gravity within limits, or an API gravity or specific gravity within limits when compared to the supplier's certificate;

2. a flash point within limits for ASTM 2D fuel oil, and, if gravity was not determined by comparison with supplier's certification, a kinematic viscosity within limits for ASTM 2D fuel oil; and

3. a clear and bright appearance with proper color.

b. Other properties for ASTM 2D fuel oil are within limits within 30 days following sampling and addition to storage tanks; and

c. Total particulate concentration of the fuel oil is ≤ 10 mg/l when tested every 31 days.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Diesel Fuel Oil Testing Program surveillance frequencies.

5.5.14 Technical Specifications (TS) Bases Control Program

This program provides a means for processing changes to the Bases of these Technical Specifications.

a. Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews

b. Licensees may make changes to Bases without prior NRC approval provided the changes do not require either of the following:

1. a change in the TS incorporated in the license; or

2. a change to the updated FSAR or Bases that requires NRC approval pursuant to 10 CFR 50.59.

d. The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the FSAR.

e. Proposed changes that meet the criteria of (b) above shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e).

(continued)

5.5 Programs and Manuals (continued)

5.5.15 Safety Function Determination Program (SFDP)

This program ensures loss of safety function is detected and appropriate actions taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other appropriate actions may be taken as a result of the support system inoperability and corresponding exception to entering supported system Condition and Required Actions. This program implements the requirements of LCO 3.0.6. The SFDP shall contain the following:

a. Provisions for cross train checks to ensure a loss of the capability to perform the safety function assumed in the accident analysis does not go undetected;

b. Provisions for ensuring the plant is maintained in a safe condition if a loss of function condition exists;

c. Provisions to ensure that an inoperable supported system's Completion Time is not inappropriately extended as a result of multiple support system inoperabilities; and

d. Other appropriate limitations and remedial or compensatory actions.

A loss of safety function exists when, assuming no concurrent single failure, a safety function assumed in the accident analysis cannot be performed. For the purpose of this program, a loss of safety function may exist when a support system is inoperable, and:

a. A required system redundant to the system(s) supported by the inoperable support system is also inoperable; or

b. A required system redundant to the system(s) in turn supported by the inoperable supported system is also inoperable; or

c. A required system redundant to the support system(s) for the supported systems (a) and (b) above is also inoperable.

The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

(continued)

5.5 Programs and Manuals (continued)

5.5.16 MS and FW Piping Inspection Program

This program shall provide for the inspection of the four Main Steam and Feedwater lines from the containment penetration flued head outboard welds, up to the first five-way restraint. The extent of the inservice examinations completed during each inspection interval (ASME Code Section XI) shall provide 100% volumetric examination of circumferential and longitudinal welds to the extent practical. This augmented inservice inspection is consistent with the requirements of NRC Branch Technical Position MEB 3-1, "Postulated Break and Leakage Locations in Fluid System Piping Outside Containment," November 1975 and Section 6.6 of the FSAR.

5.5.17 Containment Leakage Rate Testing Program

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

1. Leakage rate testing for containment purge valves with resilient seals is performed once per 18 months in accordance with LCO 3.6.3, SR 3.6.3.6 and SR 3.0.2.

2. Containment personnel air lock door seals will be tested prior to reestablishing containment integrity when the air lock has been used for containment entry. When containment integrity is required and the air lock has been used for containment entry, door seals will be tested at least once per 30 days during the period that containment entry(ies) is (are) being made.

3. The visual examination of containment concrete surfaces intended to fulfill the requirements of 10 CFR 50, Appendix J, Option B testing, will be performed in accordance with the requirements of and frequency specified by ASME Section XI Code, Subsection IWL, except where relief or alternative has been authorized by the NRC. At the discretion of the licensee, the containment concrete visual examinations may be performed during either power operation, e.g., performed concurrently with other containment inspection-related activities such as tendon testing, or during a maintenance/refueling outage.

(continued)

5.5 Programs and Manuals

5.5.17 Containment Leakage Rate Testing Program (continued)

4. A one time exception to NEI 94-01, Rev. 0, "Industry Guidelines for Implementing Performance-Based Option of 10 CFR 50, Appendix J":

   Section 9.2.3: The next Type A test, after the March 2002 test for Unit 1 and the March 1995 test for Unit 2, shall be performed within 15 years.

The peak calculated primary containment internal pressure for the design basis loss of coolant accident, P_a, is 37 psig.

The maximum allowable containment leakage rate, L_a, at P_a, is 0.2% of primary containment air weight per day.

Leakage rate acceptance criteria are:

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

b. Air lock testing acceptance criteria are:

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

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

The provisions of SR 3.0.2 do not apply to the test frequencies specified in the Containment Leakage Rate Testing Program.

The provisions of SR 3.0.3 are applicable to the Containment Leakage Rate Testing Program.

5.5.18 Configuration Risk Management Program

The Configuration Risk Management Program (CRMP) provides a proceduralized risk-informed assessment to manage the risk associated with equipment inoperability. The program applies to technical specification structures, systems, or components for which a risk-informed allowed outage time has been granted. The program shall include the following elements:

(continued)

5.5 Programs and Manuals

5.5.18 Configuration Risk Management Program (continued)

a. Provisions for the control and implementation of a Level 1 at power internal events PRA-informed methodology. The assessment shall be capable of evaluating the applicable plant configuration.

b. Provisions for performing an assessment prior to entering the LCO Condition for preplanned activities.

c. Provisions for performing an assessment after entering the LCO Condition for unplanned entry into the LCO Condition.

d. Provisions for assessing the need for additional actions after the discovery of additional equipment out of service conditions while in the LCO Condition.

e. Provisions for considering other applicable risk significant contributors such as Level 2 issues and external events, qualitatively or quantitatively.

5.5.19 Battery Monitoring and Maintenance Program

This program provides for restoration and maintenance, based on the recommendations of IEEE Standard 450-1995, "IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications," of the following:

a. Actions to restore battery cells with float voltage < 2.13 V, and

b Actions to equalize and test battery cells that had been discovered with electrolyte level below the top of the plates.

5.6 Reporting Requirements

5.6.9 Deleted.

5.6.10 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. 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. Following completion of a Unit 1 inspection performed in Refueling Outage 14 (and any inspections performed in the subsequent operating cycle), the number of indications and location, size, orientation, whether initiated on primary or secondary side for each service-induced flaw within the thickness of the tubesheet, and the total of the circumferential components and any circumferential overlap below 17 inches from the top of the tubesheet as determined in accordance with TS 5.5.9.c.3;

i. Following completion of a Unit 1 inspection performed in Refueling Outage 14 (and any inspections performed in the subsequent operating cycle), the primary to secondary LEAKAGE rate observed in each SG (if it is not practical to assign 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 which is the subject of the report; and

j. Following completion of a Unit 1 inspection performed in Refueling Outage 14 (and any inspections performed in the subsequent operating cycle), the calculated accident leakage rate from the portion of the tube below 17 inches from the top of the tubesheet for the most limiting accident in the most limiting SG.

5.5 Programs and Manuals

5.5.9 Steam Generator (SG) Program (continued)

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 1 gpm per SG.

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

c. Provisions for SG tube repair criteria. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged.

The following alternate tube repair criteria ~~may~~shall be applied as an alternative to the 40% depth based criteria:

1. For Unit 2 during Refueling Outage 11 and the subsequent operating cycle, degradation found in the portion of the tube below 17 inches from the top of the hot leg tubesheet does not require plugging.

   For Unit 2 during Refueling Outage 11 and the subsequent operating cycle, degradation identified in the portion of the tube from the top of the hot leg tubesheet to 17 inches below the top of the tubesheet shall be plugged upon detection.

2. For Unit 1 during Refueling Outage 13 and the subsequent operating cycle, and for Unit 2 during Refueling Outage 12 and the subsequent operating cycle, degradation identified in the portion of the tube below 17 inches from the top of the hot leg tubesheet does not require plugging.

   For Unit 1 during Refueling Outage 13 and the subsequent operating cycle, and for Unit 2 during Refueling Outage 12 and the subsequent operating cycle, degradation identified in the portion of the tube from the top of the hot leg tubesheet to 17 inches below the top of the hot leg tubesheet shall be plugged upon detection.

Insert for TS Page 5.5-8

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

(continued)

Insert for TS page 5.5-8:

3. For Unit 1 during Refueling Outage 14 and the subsequent operating cycle, tubes with flaws having a circumferential component less than or equal to 203 degrees found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet do not require plugging. Tubes with flaws having a circumferential component greater than 203 degrees found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet shall be removed from service.

   Tubes with service-induced flaws located within the region from the top of the tubesheet to 17 inches below the top of the tubesheet shall be removed from service. Tubes with service-induced axial cracks found in the portion of the tube below 17 inches from the top of the tubesheet do not require plugging.

   When more than one flaw with circumferential components is found in the portion of the tube below 17 inches from the top of the tubesheet and above 1 inch from the bottom of the tubesheet with the total of the circumferential components greater than 203 degrees and an axial separation distance of less than 1 inch, then the tube shall be removed from service. When the circumferential components of each of the flaws are added, it is acceptable to count the overlapped portions only once in the total of circumferential components.

   When one or more flaws with circumferential components are found in the portion of the tube within 1 inch from the bottom of the tubesheet, and the total of the circumferential components found in the tube exceeds 94 degrees, then the tube shall be removed from service. When one or more flaws with circumferential components are found in the portion of the tube within 1 inch from the bottom of the tubesheet, and within 1 inch axial separation distance of a flaw above 1 inch from the bottom of the tubesheet, and the total of the circumferential components found in the tube exceeds 94 degrees, then the tube shall be removed from service. When the circumferential components of each of the flaws are added, it is acceptable to count the overlapped portions only once in the total of circumferential components.

5.6 Reporting Requirements

5.6.9 Deleted.

5.6.10 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. 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~~.~~

Insert for TS Page 5.6-6

Insert for TS page 5.6-6:

h. Following completion of a Unit 1 inspection performed in Refueling Outage 14 (and any inspections performed in the subsequent operating cycle), the number of indications and location, size, orientation, whether initiated on primary or secondary side for each service-induced flaw within the thickness of the tubesheet, and the total of the circumferential components and any circumferential overlap below 17 inches from the top of the tubesheet as determined in accordance with TS 5.5.9.c.3;

i. Following completion of a Unit 1 inspection performed in Refueling Outage 14 (and any inspections performed in the subsequent operating cycle), the primary to secondary LEAKAGE rate observed in each SG (if it is not practical to assign 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 which is the subject of the report; and

j. Following completion of a Unit 1 inspection performed in Refueling Outage 14 (and any inspections performed in the subsequent operating cycle), the calculated accident leakage rate from the portion of the tube below 17 inches from the top of the tubesheet for the most limiting accident in the most limiting SG.

Vogtle Electric Generating Plant Units 1 and 2
Response to Request for Additional Information Related to
License Amendment Request to Revise Technical Specification (TS)
Sections 5.5.9, "Steam Generator (SG) Program" and TS 5.6.10, "Steam Generator Tube Inspection Report" for Interim Alternate Repair Criterion

Enclosure 5

Westinghouse Electric Company LLC LTR-CDME-08-43 NP-Attachment,
"Response to NRC Request for Additional Information
Relating to LTR-CDME-08-11 NP-Attachment"