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SOUTHERN COMPANY
*Energy to Serve Your World*℠

February 8, 2008

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50-425

NL-08-0107

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D. C. 20555-0001

Vogtle Electric Generating Plant
License Renewal – Audit Question Responses

Ladies and Gentlemen:

By letter dated June 27, 2007, Southern Nuclear Operating Company (SNC) submitted a License Renewal Application (LRA) for Vogtle Electric Generating Plant (VEGP) Units 1 and 2, seeking to extend the terms of the operating licenses an additional 20 years beyond the current expiration dates.

From October 15-19, 2007, and from December 10-14, 2007, the NRC conducted audits of the aging management reviews, aging management programs, and time-limited aging analyses described in the LRA. Approximately 193 audit questions were submitted to SNC in the course of these audits. The SNC responses to these questions have been submitted to the NRC staff either during or subsequent to the audits. The formal answers to these audit questions are provided in the enclosure to this letter.

(Affirmation and signature are provided on the following page.)

A129
NRR

Mr. T. 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.

The NRC commitments contained in this letter are listed in the updated License Renewal Commitment List, to be provided concurrently with the first LRA amendment.

Respectfully submitted,

SOUTHERN NUCLEAR OPERATING COMPANY

T. E. Tynan

T. E. Tynan
Vice President – Vogtle

*Sworn to and subscribed before me this* 8th *day of* February, *2008.*

Henry N. Chandler
*Notary Public*

Notary Public, Burke County, Georgia
*My commission expires:* My Commission Expires January 13, 2012

TET/JAM/daj

Enclosure: VEGP License Renewal Audit Question Responses

cc: Southern Nuclear Operating Company

| | |
|---|---|
| Mr. J. T. Gasser, Executive Vice President | w/o Enclosure |
| Mr. T. E. Tynan, Vice President – Vogtle | w/o Enclosure |
| Mr. D. H. Jones, Vice President – Engineering | w/o Enclosure |
| Mr. B. J. George, Manager, Nuclear Licensing | w/ Enclosure |
| Mr. N. J. Stringfellow, Licensing Supervisor, Vogtle | w/ Enclosure |
| RType: CVC7000 | |

U. S. Nuclear Regulatory Commission

| | |
|---|---|
| Mr. V. M. McCree, Acting Regional Administrator | w/ Enclosure |
| Mr. S. P. Lingam, NRR Project Manager – Vogtle | w/ Enclosure |
| Mr. G. J. McCoy, Senior Resident Inspector – Vogtle | w/ Enclosure |
| Mr. D. J. Ashley, License Renewal Project Manager, Vogtle | w/ Enclosure |

State of Georgia

| | |
|---|---|
| Mr. N. Holcomb, Commissioner – Department of Natural Resources | w/o Enclosure |

**Vogtle Electric Generating Plant**

**Enclosure**

**VEGP License Renewal Audit Question Responses**

# Vogtle License Renewal Audit Questions and Answers

## AMR Audit - 3.0-01

LRA AMR Table 1s (Tables 3.1.1, 3.2.1, 3.3.1, 3.4.1, 3.5.1, and 3.6.1) include line-items that list TLAA, in the aging management program column, for managing/evaluating identified aging effects, and address their corresponding further evaluation subsections in Section 3. These further evaluation subsections refer to subsections of LRA Section 4, "Time Limited Aging Analysis," for additional discussions for the LRA Table 1 line-items. However, Section 4.0 does not provide details of the component/structure, material, environment, and aging effects combinations that are evaluated by the TLAA. In addition, some of the further evaluation subsections of Section 3 and their corresponding TLAA sections credit an aging management program in accordance with 10 CFR 54.21(c)(1)(iii). These are not identified in their corresponding Table 2 as specified in LRA Section 3.0.2.3. For example, subsection 3.1.2.2.1 states that the Fatigue and Cycle Monitoring Program is credited to disposition the fatigue TLAA of specific components.

In order for the staff to complete the safety review of the VEGP LRA, the staff needs to understand how aging effects for the components/structures identified in the LRA Section 2 are subject to an AMR are determined and managed. Therefore, please provide details on the component/structure, material, environment, and aging effect combinations that are evaluated by TLAA. Also, clearly identify those line-items that credit an aging management program in addition to/instead of a TLAA.

## VEGP Response:

VEGP LRA "Table 1s" (i.e. Tables 3.1.1, 3.2.1, 3.3.1, 3.4.1, 3.5.1, and 3.6.1) address the applicability of aging effects associated with line items in GALL. For those components associated with a TLAA, the further evaluation describes the TLAA and refers to section 4 of the LRA where the TLAA is discussed in more detail. Table 4.1.2-1 of section 4 lists the TLAAs applicable to VEGP. In this table, the disposition method from 10CFR54.21(c)(1) is identified.

For TLAAs where the existing analysis remains valid, i.e. demonstration in accordance with 10CFR54.21 (c)(1)(i), or TLAAs where analyses have been projected to the end of the period of extended operation, i.e.10CFR54.21 (c)(1)(ii), there is not a resulting aging effect requiring management for the period of extended operation. For these items, there are not associated line items in the AMR results tables (Table 2s) in Section 3.

For TLAAs where disposition requires an AMR, i.e. 10CFR54.21(c)(1)(iii), an AMR is required and there are associated line items included in the AMR results tables (Table 2s) in Section 3.

For Table 3.1.2-3 item 9a and for Table 3.1.2-4 items 2b, 3b, 4b, 6b, 7b, 10a, 11a; the aging effect requiring management will be changed from "Cracking - Cyclic Loading" to "Cracking - Thermal Fatigue", the Fatigue Monitoring Program will be included as the sole aging management program credited, and the GALL linkage will be changed to GALL item IV.C2-25. Item 9a was included in Table 3.1.2-4 in error and will be deleted from Table 3.1.2-4. For Item 8a in Table 3.1.2-3, the Aging Effect Requiring Management is changed from "Cracking - Cyclic Loading" to "Cracking - Thermal Loading" and the Fatigue Monitoring Program is removed from the Aging Management Programs. A new item, 8e, is added to Table 3.2.1-3 with the same Component type, intended function, material, and environment as Item 8a. The aging effect requiring management for the new item is Cracking - Thermal Fatigue. The aging management program for the new item is the Fatigue Monitoring Program. The NUREG-1801 Vol. 2 Item is IV.C2-25. The Table 1 Item for the new item is 3.1.1-8 and the Note is E.

For Table 3.1.2-5 items 2a and 8a, the aging effect requiring management will be changed from

"Cracking - Cyclic Loading" to "Cracking - Thermal Fatigue", the Fatigue Monitoring Program will be included as the sole aging management program credited, and the GALL linkage will be changed to GALL item IV.D1-11.

For Table 3.1.2-5 item 6a, the aging effect requiring management will be changed from "Cracking - Cyclic Loading" to "Cracking - Thermal Fatigue." There is no change to the AMP.

LRA Table 3.1.1 items associated with the above described changes will be amended accordingly.

The following is a list of the PWR Table 1 line items associated with TLAAs and either a statement that there are no related Table 2 items, or a list of Table 2 items that are related.

| | |
|---|---|
| Table 3.1.1, item 3.1.1-1 - | There are no Table 2 items related to this item. |
| Table 3.1.1, item 3.1.1-5 - | There are no Table 2 items related to this item. |
| Table 3.1.1, item 3.1.1-6 - | There are no Table 2 items related to this item. |
| Table 3.1.1, item 3.1.1-7 - | Table 3.1.2-5 item 6a is currently related to this item. Additionally, the LRA will be amended to relate LRA Table 3.1.2-5 items 2a and 8a to this GALL item. |
| Table 3.1.1, item 3.1.1-8 - | The LRA will be amended to relate new item 8e and existing item 9a in Table 3.1.2-3 and items 2b, 3b, 4b, 6b, 7b, 10a, and 11a in Table 3.1.2-4 to this item. |
| Table 3.1.1, item 3.1.1-9 - | There are no Table 2 items related to this item. |
| Table 3.1.1, item 3.1.1-10 - | There are no Table 2 items related to this item. |
| Table 3.1.1, item 3.1.1-17 - | There are no Table 2 items related to this item. |
| Table 3.1.1, item 3.1.1-21 - | There are no Table 2 items related to this item. |
| Table 3.2.1, item 3.2.1-1 - | There are no Table 2 items related to this item. |
| Table 3.3.1, item 3.3.1-1 - | There are no Table 2 items related to this item. |
| Table 3.3.1, item 3.3.1-2 - | There are no Table 2 items related to this item. |
| Table 3.4.1, item 3.4.1-1 - | There are no Table 2 items related to this item. |
| Table 3.5.1, item 3.5.1-7 - | There are no Table 2 items related to this item. |
| Table 3.5.1, item 3.5.1-9 - | There are no Table 2 items related to this item. |
| Table 3.5.1, item 3.5.1-42 - | There are no Table 2 items related to this item. Further, this TLAA is not applicable to VEGP. |
| Table 3.6.1, item 3.6.1-1 - | There are no Table 2 items related to this item. |

SNC will amend the LRA to make the changes to Table 2s described above and to provide clarifying detail in the LRA Sections referenced in the Table 1s. Where a TLAA is dispositioned using an aging management program, a note will be added to clarify which Table 2 items are dispositioned by an aging management program. Where a TLAA is not dispositioned using an aging management program, a note will be added to clarify that there are no associated items in the Table 2s. Where other sections are identified as being inconsistent with the changes due to the response to this question, the LRA amendment will change those sections to be consistent with the response to this question. This includes the Discussion column for items 21, 62, 67, and 70 in Table 3.1.1.

A License Renewal Application amendment is required.

## AMR Audit - 3.1-01

In LRA Table 3.1.1, item 3.1.1-1, under discussion column, the applicant states that this item is not applicable to VEGP. The VEGP reactor pressure vessels are a Westinghouse design without a support skirt. Therefore, the applicable GALL Report IV.A2-20 was not used. Section 5.4.14.2.1 of VEGP FSAR states that support for the reactor vessel are individual, air cooled, rectangular box structure beneath the vessel nozzles bolted to the primary shield wall concrete. GALL Table 1, line-item 1 identifies cumulative fatigue damage as the aging effect and recommends TLAA evaluation in accordance with 10 CFR 54.21(C). Although VEGP reactor vessels are not supported by a support skirt, the staff finds cumulative fatigue damage aging effect applicable to the rectangular support structures, which is listed as item 17 in LRA Table 3.1.2-1. Please explain why cumulative fatigue damage aging effect is not considered for the reactor supports.

## VEGP Response:

Cumulative fatigue damage is an applicable TLAA for the VEGP reactor vessel supports. As stated in LRA Section 4.3.4, the existing analysis is demonstrated to be valid for the extended term of operation in accordance with 10 CFR 54.21(c)(1)(i). See the response to question 4.3-08 for more details.

As described in VEGP response to question 3.0-01, for TLAAs in which the existing analysis remains valid - 10CFR54.21 (c)(1)(i), there is no aging effect requiring management for the period of extended operation based on the TLAA disposition, and therefore these TLAA items are not included in the Table 2s in Section 3.

The discussion for Table 1 item 3.1.1-1 will be revised to clarify that fatigue of the VEGP RPV support pads is a TLAA and is discussed in Section 4.3 of the VEGP LRA.

A License Renewal Application amendment is required.

## AMR Audit - 3.1-02

LRA Table 3.1.2-5, item 29b, credits Water Chemistry Control Program, Inservice Inspection Program, and Steam Generator Tubing Integrity Program for managing loss of material aging effects for alloy steel tube plates exposed to treated water. LRA claims consistency with the GALL Report IV.D1-12, which rolls up to GALL Table 1 item 3.1.1-16. It also uses a standard Note E, which means that this AMR item is consistent with the GALL Report for material, environment, and aging effect, but a different aging management program is credited. GALL Report Table 1, item 16, and GALL Report IV.D1-12 address loss of material due to general, pitting, and crevice corrosion for the steam generator upper and lower shell, and transition cone fabricated from steel and exposed to secondary feedwater/steam. GALL recommends Water chemistry and ISI programs for managing this aging effect. In addition GALL states that "As noted in NRC IN 90-04, if general and pitting corrosion of the shell is known to exist, the AMP guidelines in Chapter XI.M1 may not be sufficient to detect general and pitting corrosion (and the resulting corrosion-fatigue cracking), and additional inspection procedures are to be developed"

a. Explain how LRA component type is consistent with the GALL component type for this AMR line-item
b. Explain whether the Steam Generator Tube Integrity (SGTI) Program is used to augment the ISI Program, as noted in NRC IN 90-04, and discuss the additional inspections that are performed to detect general and pitting corrosion (and the resulting corrosion-fatigue cracking)
c. Also, please explain why SGTI program is not used for other steam generator components that are rolled up to Table 3.1.1, item 3.1.1-16 (Table 3.1.2-5 items 2b, 8b, 20a, 21a, 24a, 25a, 29a, 31a, and 32a).

## VEGP Response:

SNC responses to audit question parts a, b, and c are provided below.

a. Standard Note E does not refer to component type consistency with NUREG-1801. As a result, application of Note E in the VEGP does not imply component type consistency. Additionally, LRA Table 3.1.1 item 16 identifies the tubeplate alignment with NUREG-1801 Rev. 1 item IV.D12 as a substitute, not a component match. Also see text below related to correction of Standard Note E wording.

b. For the steam generator tubeplate, ASME Section XI requirements, as implemented by the VEGP ISI Program are applicable and would be capable of detecting significant loss of material due to localized corrosion. Steam Generator Tubing Integrity Program inspections include visual examination of the secondary side of the tubeplate and eddy current examination / UT of steam generator tubing. These inspections are capable of providing indications of localized corrosion associated with steam generator tube to tubeplate interfaces. In an effort to align with NUREG-1801 where possible, SNC aligned corrosion of the tubeplate to NUREG-1801 Rev. 1 item IV.D1-12. Alternatively, SNC could have aligned to NUREG-1801 Rev. 1 item IV.D1-9. However, item IV.D1-9 includes erosion as an applicable aging mechanism in addition to corrosion, which could have also been misinterpreted by the staff. As a result, SNC believed item IV.D1-12 to be the best match available in NUREG-1801 Section IV.D1. Finally, the corrosion fatigue issues described in NRC IN are not applicable to the steam generator tubeplate.

c. With the exception of item 29a, the LRA Table items listed in part c of the audit question relate to steam generator secondary side pressure boundary components exposed to treated water. Aging management of these ASME Code Safety Class 2 components is not addressed by NEI

97-06 and are therefore not within the scope of the VEGP Steam Generator Program. However, these components are within the scope of the VEGP ISI Program.

Item 29a relates to the nickel alloy clad, primary side of the steam generator tubeplate. Corrosion of this location is considered to be mitigated by water chemistry controls alone. Also see the VEGP response to audit question 3.1-18.

VEGP LRA correction regarding Standard Note E:
VEGP LRA Section 3.0, Table 3.0-4 correctly states Note E as:
"Consistent with NUREG-1801 item for material, environment, and aging effect, but a different aging management program is credited or NUREG-1801 identifies a plant-specific aging management program."

VEGP Standard Note lists for Sections 3.1, 3.2, 3.3, 3.4, 3.5, and 3.6 incorrectly reproduce Note E in that the following words from Note E are omitted:
"or NUREG-1801 identifies a plant-specific aging management program."

SNC amends the VEGP LRA by replacing the Note E wording in Sections 3.1, 3.2, 3.3, 3.4, 3.5, and 3.6 with the Note E wording contained in Table 3.0-4.

A license renewal application amendment is required.

## AMR Audit - 3.1-03

In LRA Table 3.1.1, item 3.1.1-21, under discussion column, the applicant states that this item is not applicable to VEGP. Also, in LRA Section 3.1.2.2.5, "Crack Growth due to Cyclic Loading," the applicant states that:

> NUREG-1800 Section 3.1.2.2.5 indicates that crack growth due to cyclic loading could occur in reactor vessel SA 508 Class 2 forgings clad with stainless steel using a high heat input process. There are no analyses of underclad flaws in the VEGP reactor vessels and therefore no TLAA exists for VEGP.
>
> There are SA-508 Class 2 forgings clad using high heat input processes in the VEGP reactor pressure vessel. However, weld processes used were subject to qualification and performance testing as described in NRC Regulatory Guide 1.43 to ensure that underclad cracking would not occur. NRC Regulatory Guide 1.43 describes acceptable methods for preventing underclad cracking through selection and control of the weld processes used for cladding ferritic steel components with stainless steel.

The NRC staff notes that the methods described in RG 1.43 are to limit the occurrence of underclad cracking in low-alloy steel safety related components clad with stainless steel. Therefore, fabrication of these components in accordance with the guidelines in RG 1.43 does not exempt these components from performing TLAA during the period of extended operation. In addition, pursuant to 10 CFR 54.21(c)(1)(iii), LR-SRP Section 4.7.2.1, states that the applicant should demonstrate that the effects of aging on the intended function will be adequately managed for the period of extended function, if no TLAA exists.

a. Identify VEGP reactor pressure vessel components/portions that are made of SA-508 Class 2 steel forgings clad with stainless steel
b. Please provide additional justification for not using TLAA for evaluation of underclad cracking in low-alloy steel safety related components clad with stainless steel
c. Explain how crack growth due to cyclic loading is managed for these components

## VEGP Response:

Responses to parts a, b, and c of the audit question are provided below:

a. VEGP reactor pressure vessel components forged in accordance with ASME SA-508 Cl. 2 and internally clad with stainless steel weld material include the closure head dome flanges (Table 3.1.2-1 item 4), primary inlet nozzles (Table 3.1.2-1 item 17), primary outlet nozzles (Table 3.1.2-1 item 20), and vessel flanges (Table 3.1.2-1 item 25).

b. While there are no known under-clad cracks within the VEGP reactor vessels and controls on welding processes were implemented to minimize the potential for development of under-clad cracks, the LRA will be amended to include under-clad cracking as a TLAA for the components listed in part a above.

c. Analyses performed by Westinghouse in WCAP-15338 demonstrate that growth of under-clad cracks in Westinghouse reactor pressure vessels (RPVs) does not represent a significant challenge to reactor vessel integrity for an operating term of 60 years. The assumptions used as inputs to WCAP-15338 are applicable to VEGP. The results of these analyses demonstrate that under-clad cracking of reactor vessel components is not an aging effect requiring management for VEGP. TLAA disposition is in accordance with 10 CFR 54.21(c)(1)(i).

A License Renewal Application amendment is required.

## AMR Audit - 3.1-04

LRA Table 3.1.2-5, items 7b, 11b, and 2b, credit Steam Generator Program for Upper internals for managing loss of material due flow accelerated corrosion (FAC) for feedwater distribution assembly piping, fittings, and supports, and steam generator primary and secondary moisture separators fabricated of carbon steel and exposed to treated water/steam. LRA claims consistency with the GALL Report IV.D1-26, which rolls up to GALL Table 1 item 3.1.1-32. It also uses a standard Note E, which means that this AMR item is consistent with the GALL Report for material, environment, and aging effect, but a different aging management program is credited. GALL Report IV.D1-26 and Table 1 item 3.1.1-32 identify wall thinning due to FAC for this component, material and environment combination, and recommends a plant specific program to be evaluated with reference to NRC IN 91-19, "Steam Generator Feedwater Distribution Piping Damage."

a. Please explain how LRA aging effect is consistent with the GALL Report for this component, material, and environment
b. Discuss the basis for crediting Steam Generator Program for Upper internals. Refer to NRC IN 91-19 in your discussions

## VEGP Response:

SNC assumes that the staff intended to list Table 3.1.2-5 item "12b" and not item "2b." Item 2b from Table 3.1.2-5 does not relate to flow-accelerated corrosion.

NUREG-1801 Rev. 1 item IV.D1-26 is a reasonable match for VEGP Table 3.1.2-5 items 7b, 11b, and 12b. The material of construction, environment, and postulated aging effect are all similar. Even though the Westinghouse Model F steam generator design is different than the Combustion Engineering design and has not experienced significant degradation of the feedwater ring assembly due to flow-accelerated corrosion, SNC conservatively postulates FAC degradation mechanism for the feedring assembly and moisture separators.

Detection of aging effects in the steam generator secondary-side internals is primarily accomplished through the use of visual inspections. Consistent with NEI 97-06, the Steam Generator Program for Upper Internals includes inspection activities intended to detect degradation of secondary side internals needed to maintain tubing integrity and accomplishment of the steam generator intended functions. An assessment based upon SG design, potential degradation mechanisms, and related VEGP and industry operating experience is performed to establish inspection requirements for secondary side internals components. These activities are adequate to detect FAC of carbon steel steam generator internals components prior to a loss of intended function.

The issues prompting Information Notice 91-19 are not applicable to Westinghouse Model F steam generators. The issues described in IN 91-19 relate to specific feedwater distribution system design issues associated with some Combustion Engineering steam generators. Different than the design of concern described in IN 91-19, Model F steam generators do not distribute both feedwater and auxiliary feedwater flow via a common nozzle. The VEGP Model F steam generator design includes separate nozzles for normal feedwater and auxiliary feedwater. Additionally, operating experience has shown that Model F feedwater distribution assemblies are not susceptible to the same thermal loadings as those described in IN 91-19.

## AMR Audit - 3.1-05

LRA Table 3.1.2-1, items 7a (Conoseal Assemblies (Unit 1) and Core Exit Nozzle Thermocouple (Unit 2) Assemblies), 11a (CRDM Housing Adapters), and 12a (CRDM Latch Housings and Rod Travel Housings) credit Water Chemistry Control Program and Inservice Inspection Program (ISI) for managing cracking due to stress corrosion cracking (SCC) for stainless steel components exposed to borated water. LRA claims consistency with the GALL Report IV.A2-11, which rolls up to GALL Table 1 item 3.1.1-34. It also uses a standard Note E, which means that these line-items are consistent with the GALL Report for material, environment, and aging effect, but a different aging management program is credited. GALL Report IV.A2-11 also recommends Water Chemistry and ISI for managing cracking due to SCC for components fabricated from stainless steel. Clarify why Note E is used for these line items.

## VEGP Response:

The VEGP Inservice Inspection Program is categorized as an existing, plant-specific AMP. SNC maintains that Note E is appropriate since the definition of Note "E" includes the use of plant-specfic programs. The definition of Note E is as follows: "Consistent with NUREG 1801 for material, environment, and aging effect, but a different AMP is credited or NUREG 1801 identifies a plant specific aging management program."

## AMR Audit - 3.1-06

LRA Table 3.1.2-1, identifies cracking due to SCC (item 26a), loss of material due to pitting and crevice corrosion (item 26b), and loss of material due to wear (26c) for stainless steel "Vessel Head Thermal Sleeves" in borated water. LRA credits Water Chemistry Control Program for managing cracking due to stress corrosion cracking (SCC) and loss of material due to pitting and crevice corrosion. For item 26a, LRA claims consistency with the GALL Report IV.A2-11, which rolls up to GALL Table 1 item 3.1.1-34. It also uses a standard Note E and a plant specific Note 101. For item 26b, claims consistency with the GALL Report IV.A2-14, which rolls up to GALL Table 1 item 3.1.1-83. It also uses a standard Note C and a plant specific Note 101. For item 26c, LRA credits Reactor Vessel Internal Program for managing loss of material due wear. LRA uses a standard Note H and a plant specific Note 101. Note 101 states that "The VEGP Reactor Vessel Heads incorporate thermal sleeves for the CRDM penetrations. The primary use of these thermal sleeves is to accommodate normal random misalignments of the drive rod. The thermal sleeve provides the centering guidance for leading the drive rod into the CRDM. Wear of these thermal sleeves has been identified as an aging effect requiring management based on recent plant specific operating experience."

a. GALL Report item IV.A2-11 recommends using Water Chemistry and ISI programs for managing cracking due SCC. Explain how Water Chemistry program alone can manage this aging effect for the reactor vessel head thermal sleeves (item 26a).
b. For item 26b, it appears that this item is consistent with the GALL Report item IV.C2-15 that rolls up to GALL Table 1 item 3.1.1-83. Clarify whether this item is consistent with GALL Report item IV.A2-14.
c. For item 26c, discuss how Reactor Vessel Internal Program alone manages loss of material due to wear for the stainless steel reactor vessel head thermal sleeves in borated water. ( Ref. Question B.3.24-4 for commitment # 20).

## VEGP Response:

In response to part a:
There are a number of mitigating factors which, when taken together, indicate that stress corrosion cracking of the thermal sleeves can be managed with water chemistry control alone:

First, the sleeve assemblies are shop fabricated and heat treated. As such, there are no full penetration field welds associated with this assembly. Additionally, component materials were tested for corrosion susceptibility at the fabrication shop. A susceptible material is one of the three key factors required for SCC susceptibility.

Second, the thermal sleeves are not subject to high tensile stresses. One end of the thermal sleeve hangs freely into the vessel upper head area, with no restraint. The presence of significant tensile stresses is the second of the three key factors required for SCC susceptibility. Even if cracking is initiated in a region of higher stress, the material is not loaded in such a way as to maintain stress loads. Any postulated cracks would be expected to arrest once entering an area of lower stress.

Third, the reducing nature of the primary water chemistry environment has been shown to be generally effective in mitigating stress corrosion cracking. Events associated with PWR stress corrosion cracking have generally been associated with off-normal chemistry specifications or intrusion events. The presence of a conducive environment is the third of the three key factors required for SCC susceptibility. Recent operating experience reviews did not identify any stress corrosion cracking of vessel head thermal sleeves in domestic PWRs. VEGP has no history of stress corrosion cracking at this location.

In response to part b:
SNC confirms that the VEGP conclusion for loss of material due to corrosion associated with the vessel head thermal sleeves is consistent with NUREG-1801 Rev. 1 item IV.A2-14. Consistency with IV.C2-15 could have also been included. In either case, the resulting aging management approach is the same and is summarized in Table 3.1.1 Item 83.

In response to part c:
See the VEGP response to Audit Question B.3.24-2 for a summary of the reactor vessel head thermal sleeve wear identified at VEGP. As stated in the VEGP response to audit question B.3.24-2, SNC considers this issue to be an emerging current term issue. Existing aging management programs are not considered to be sufficient to manage this issue. As such, the Reactor Vessel Internals Program is the vehicle chosen by SNC to ensure wear of the vessel head thermal sleeves is adequately managed during the period of extended operation. Aging management may consist of visual or other NDE and may include wear rate calculations, similar to evaluations performed to address wear of flux thimbles. However, at this date, sufficient data is not available to establish a fixed aging management strategy to address this issue. To specifically address this issue VEGP amended future action commitment list item no. 20 for the Reactor Vessel Internals Program to specifically address the vessel head thermal sleeves.

## AMR Audit - 3.1-07

LRA Table 3.1.2-3, item 20g, credits LRA AMP B.3.8, External Surfaces Monitoring Program, for managing loss of material for carbon steel valve bodies exposed to indoor air. LRA claims consistency with the GALL Report VII.I-8 and GALL Table 1 item 3.1.1-58. However, GALL Report VII.I-8 and GALL Table 1 item 3.1.1-58 are not consistent. Item VII.I-8 recommends using External Surfaces Monitoring Program, but item 3.1.1-58 recommends using Boric Acid Corrosion Program. Please clarify this discrepancy and provide technical justification for using External Surfaces Monitoring Program.

## VEGP Response:

LRA Table 3.1.2-3 (Item 20g) should have been linked with GALL Table 1 item 3.3.1-58 instead of item 3.1.1-58. GALL Item 3.3.1-58 recommends using External Surfaces Monitoring Program for managing loss of material for steel external surfaces exposed to indoor air, which matches the material, environment and program combination shown in LRA Table 3.1.2-3 (Item 20g). This is also consistent with GALL Report VII.I-8. The External Surfaces Monitoring Program will visually identify loss of material due to general corrosion, such as on the external surfaces of these carbon steel valves. The valve bodies addressed by item 20g are not ASME Class 1 components but rather non-ASME Class 1 components associated with RCS support systems (e.g. oil spill protection, cooling water).

LRA Table 3.1.2-3 (Item 20g) will be revised to note the correct Table 1 item (3.3.1-58).

A License Renewal Application amendment is required to correct this discrepancy.

## AMR Audit - 3.1-08

LRA Table 3.1.2-1 items 14a (Intermediate Shell Course), 16a (Lower Shell Course), and 23a (Upper Shell Course) credits Reactor Vessel Surveillance Program for managing loss of fracture toughness aging effect for these components in borated water environment. 10 CFR 50.61 (a)(3) states that "Reactor Vessel Beltline means the region of the reactor vessel (shell material including welds, heat affected zones and plates or forgings) that directly surrounds the effective height of the active core and adjacent regions of the reactor vessel that are predicted to experience sufficient neutron radiation damage to be considered in the selection of the most limiting material with regard to radiation damage." Clarify whether welds are included in these line-items. If not, provide technical justification for excluding welds from the AMR tables.

## VEGP Response:

RPV components are constructed from alloy steels, carbon steels, nickel alloys, stainless steels, and cast austenitic stainless steels (CASS). Weld material used in component fabrication and the metallurgical effects of the welding techniques employed are included with the base material evaluated in specific reviews of materials and associated aging mechanisms. Per these reviews, the following components are considered to be subject to loss of fracture toughness due to neutron embrittlement and are monitored as a part of the Reactor Vessel Surveillance Program: Lower Shell Course (and associated welds), Intermediate Shell Course (and associated welds), and Upper (Nozzle) Shell Course Forgings
(and associated welds).

Therefore, the welds are included in the reactor components (upper, intermediate and lower shell courses) that are managed for loss of fracture toughness by the Reactor Vessel Surveillance Program.

## AMR Audit - 3.1-09

LRA Table 3.1.2-3, item 9a, credits Fatigue Monitoring Program and Inservice Inspection Program for managing cracking due to cyclic loading for stainless steel Class 1 Piping Components ? NPS 4 that are exposed to borated water. LRA claims consistency with the GALL Report IV.C2-26 that rolls up to the GALL Table 1 line 62. GALL Report IV.C2-26 recommends using Inservice Inspection Program for managing cracking due to cyclic loading. LRA uses a standard Note E and a plant special Note 105 for this line-item. Note E means that this line-item is consistent with GALL Report for material, environment, and aging effect, but a different aging management program is credited. Note 105 states that the associated GALL Report Vol. 2 item does not include all of the piping lines applicable for VEGP. Stress based fatigue monitoring to manage thermal fatigue is performed by the Fatigue and Cycle Monitoring Program for a number of VEGP ASME Class 1 piping locations."

The Fatigue Monitoring Program does not inspect for existing or postulated fatigue-initiated cracks, but rather relies on cycle monitoring to assure that the TLAAs on thermal fatigue will remain valid for the period of extended operation.

a. Clarify whether the aging effect "cracking due to cyclic loading" already postulates the initiation of a fatigue-induced crack in these piping components. If so, clarify and justify how the Fatigue Monitoring Program manages cracking due to cyclic loading in these components when the program does not perform any inspections of the components surfaces
b. Discuss the inspection methods or techniques and frequency of these inspections that are being used to detect, monitor/trend cracking due cyclic loading.
c. Also, LRA Table 3.1.1 item 3.1.1-61 item states that the VEGP pressurizer support skirt and flange is not subject to cracking due to cyclic loading. Provide technical justification for this statement.

## VEGP Response:

See VEGP response to question 3.0-01. As modified by the response to question 3.0-01, LRA Table 3.1.2-3, item 9a will reference GALL Report item IV.C2-25 that rolls up to Table 1 line 8 instead of GALL Report item IV.C2-26 that rolls up to Table 1 line 62. Table 1 item 62 will not be used by VEGP. As SNC now understands the staff's intended use of the term "cracking due to cyclic loading" in GALL, VEGP has no components with an aging effect requiring management of "Cracking - cyclic loading." The following discussion addresses each of the lettered portions of the question:

a. The SNC interpretation of "cracking due to cyclic loading" was different than the staff's. As a result, this term will be replaced with the term "Cracking - Thermal Fatigue." SNC does not postulate the pre-existence of a fatigue-induced crack.

b. Component inspections are not performed by the Fatigue Monitoring Program. The program monitors the CUF of those components that require aging management to prevent cracking due to cumulative fatigue damage.

c. UFSAR Section 3.9.N.1 describes in detail the design transients, loads, and analysis methods used to ensure the adequacy of the RCS component supports, which include the pressurizer support skirt and flange. SNC's review determined these analyses remain valid for the extended period of operation, but are not TLAAs. In structural steel components, fatigue failure is initiated by plastic deformation in a localized region. Generally, loads are applied gradually and remain constant. Dynamic loads are too infrequent to initiate fatigue cracking. Therefore, cracking due to thermal fatigue is not an aging effect requiring further evaluation for these structural components.

## AMR Audit - 3.1-10

LRA Table 3.1.2-2 items 6e, 7e, 10c, 12e, 13e, 17e, 19e, and 20e identify loss of material due to wear for stainless steel components in borated water environment. LRA uses Reactor Vessel Internals Program for managing this aging effect. It claims consistency with the GALL Report IV.B2-26 and IV.B2-34, which roll up to GALL Table 1, item 63. It uses a standard Note E, which means that this line item is consistent with the GALL Report for material, environment, and aging effect, but a different aging management program is credited. GALL Report IV.B2-26 and IV.B2-34 recommend ISI program for managing this aging effect. Provide technical justification for using RVI program in lieu of ISI program.

## VEGP Response:

See the VEGP response to audit question B.3.24-1 which describes the VEGP position regarding wear of reactor vessel internals components.

## AMR Audit - 3.1-11

LRA Table 3.1.2-2, item 5e, identifies loss of material due to wear for nickel alloy clevis inserts and fasteners in borated water environment. LRA uses Reactor Vessel Internals Program for managing this aging effect. LRA refers to the GALL Table 1, item 63 and uses a standard Note H, which means that Aging effect not in the GALL Report for this component, material, and environment combination. The staff noted that GALL Report IV.B2-34 identify loss of material due to wear for nickel alloy upper internals assembly and upper core plate alignment pins, and recommend ISI program for managing this aging effect. Explain how LRA Table 3.1.2-3 item 5e differs from this GALL Report item. Provide technical justification for using RVI program in lieu of ISI program.

## VEGP Response:

See the VEGP response to audit question B.3.24-1 which describes the VEGP position regarding wear of reactor vessel internals components.

## AMR Audit - 3.1-12

LRA Table 3.1.2-4, items 2b, 3b, 4b, 6b, 7b, 9a, 10a, and 11a, credit Fatigue Monitoring Program and Inservice Inspection Program for managing cracking due to cyclic loading for pressurizer components fabricated of stainless steel, steel with stainless steel cladding, or nickel alloy materials that are exposed to borated water. LRA uses a standard Note E which means that this line-item is consistent with the GALL Report for material, environment, and aging effect, but a different aging management program is credited. LRA claims consistency with the GALL Report line-item IV.C2-18 that rolls up to the GALL Table 1 line 67. GALL Report IV.C2-18 recommends ISI and water chemistry for managing this aging effect. The staff noted that the applicant in the discussion column of LRA Table 3.1.1 for line 67 states that Water Chemistry Control is not credited to mitigate cracking due to cyclic loading. The Fatigue Monitoring Program does not inspect for existing or postulated fatigue-initiated cracks, but rather relies on cycle monitoring to assure that the TLAAs on thermal fatigue will remain valid for the period of extended operation.

a. Clarify whether the aging effect "cracking due to cyclic loading" already postulates the initiation of a fatigue-induced crack in these piping components. If so, clarify and justify how the Fatigue Monitoring Program manages cracking due to cyclic loading in these components when the program does not credit any inspections of the components surfaces.
b. Discuss the inspection methods or techniques and frequency of these inspections that are being used to detect, monitor/trend cracking due cyclic loading

## VEGP Response:

See VEGP response to question 3.0-01. As modified by the response to question 3.0-01, LRA Table 3.1.2-4, items 2b, 3b, 4b, 6b, 7b, 10a, and 11a will reference GALL Report item IV.C2-25 that rolls up to Table 1 line 8 instead of GALL Report item IV.C2-18 that rolls up to Table 1 line 67. Item 9a is deleted from Table 3.1.2-4. Table 1 item 67 will not be used by VEGP. As SNC now understands the staff's intended use of the term "cracking due to cyclic loading" in GALL, VEGP has no components with an aging effect requiring management of "Cracking - cyclic loading." The following discussion addresses each of the lettered portions of the question:

a. The SNC interpretation of "cracking due to cyclic loading" was different than the staff's. As a result, this term will be replaced with the term "Cracking - Thermal Fatigue." SNC does not postulate the pre-existence of a fatigue-induced crack.

b. Component inspections are not performed by the Fatigue Monitoring Program. The program monitors the CUF of those components that require aging management to prevent cracking due to cumulative fatigue damage.

## AMR Audit - 3.1-13

LRA Table 3.1.2-5, item 30e,credits Steam Generator Tubing Integrity Program for managing loss of material due to wear for nickel alloy steam generator tubes exposed to treated water. LRA shows consistency with GALL Report IV.D1-24, which rolls up to GALL Report Table 1 item 72. LRA uses the standard Note E, which means this item is consistent with the GALL Report item for material, environment, and aging effect, but a different aging management program is credited. GALL Report IV.D1-24 recommends Water Chemistry Control Program and Steam Generator Tubing Integrity Program for managing this component, material, environment, and aging effect combination. Please provide bases for using Steam Generator Tubing Integrity Program alone.

Similarly, LRA Table 3.1.2-5, item 1c, credits Steam Generator Tubing Integrity Program for managing loss of material due to wear for nickel alloy Anti-Vibration Bars in treated water/steam environment. LRA shows consistency with GALL Report IV.D1-15, which rolls up to GALL Report Table 1 item 74. LRA uses the standard Note E, which means this item is consistent with the GALL Report item for material, environment, and aging effect, but a different aging management program is credited. GALL Report IV.D1-15 recommends Water Chemistry Control Program and Steam Generator Tubing Integrity Program for managing this component, material, environment, and aging effect combination. Please provide technical bases for using Steam Generator Tubing Integrity Program alone.

## VEGP Response:

Wear of SGs Anti-Vibration Bars (AVBs) and U-Tubes is considered an aging effect due to relative motion between surfaces primarily as a result of flow-induced vibration. As such, control of water chemistry is not effective to manage loss of material due to wear. However, SNC notes that water chemistry controls are generally credited to manage corrosion of the AVBs and U-Tubes.

The Steam Generator Tubing Integrity Program (SGTIP) is an effective program for management of AVB and U-Tube wear . Detection of wear is accomplished through the use of eddy current testing, visual inspections, and leakage monitoring.

## AMR Audit - 3.1-14

LRA Table 3.1.2-5, item 28a, credits Water Chemistry Control Program and Steam Generator Tubing Integrity Program for managing cracking due to stress corrosion cracking (SCC) for stainless steel steam generator tube support plates and flow distribution baffles exposed to treated water. LRA shows consistency with GALL Report IV.D1-15, which rolls up to GALL Report Table 1 item 74. LRA uses the standard Note D, which means component is different but consistent with the GALL Report item for material, environment, and aging effect. AMP takes some exceptions to the GALL AMP. However, GALL Report IV.D1-15 addresses loss of material due to crevice corrosion and fretting aging effect, for steam generator structural and anti vibration bars. Therefore LRA aging effect is different from the GALL Report for this item. Instead, it appears that LRA Table 3.12.-5, item 28a should have rolled up to GALL Item IV.D1-14 in the GALL Report, Volume 2. Please explain why LRA has considered LRA Table 3.1.2-5 item 28a aging effect consistent with the GALL Report IV.D1-15.

## VEGP Response:

LRA Table 3.1.2-5, item 28a should have been aligned to NUREG-1801 Item IV.D1-14 instead of IV.D1-15. Item 28a of LRA Table 3.1.2-5 will be revised to link to Item IV.D1-14.

A License Renewal Application amendment is required to correct this discrepancy.

## AMR Audit - 3.1-15

LRA Table 3.1.2-5, item 23a, credits Water Chemistry Control Program for managing cracking due to stress corrosion cracking (SCC) for nickel alloy steam outlet flow limiter exposed to steam. LRA shows consistency with GALL Report IV.D1-14, which rolls up to GALL Report Table 1 item 74. LRA uses the standard Note E, which means this item is consistent with the GALL Report item for material, environment, and aging effect, but a different aging management program is credited. GALL Report IV.D1-14 recommends Water Chemistry Control Program and Steam Generator Tubing Integrity Program for managing this component, material, environment, and aging effect combination. Please provide bases for using Water Chemistry Control Program alone.

## VEGP Response:

The steam outlet flow limiter is exposed to high purity secondary side steam which does not contain the impurities which have been implicated in stress corrosion cracking of thermally treated Alloy 600 tubing. Additionally, corrosion potentials are significantly different in the main steam environment, as compared with more aggressive areas of the steam generator secondary side (e.g. top of tubesheet region). Finally, no VEGP or domestic PWR operating experience related to degradation of a thermally treated Alloy 600 main steam flow limiter could be identified.

## AMR Audit - 3.1-16

Please discuss whether loss of material due to erosion or wear is a plausible aging effect for the VEGP feedwater and auxiliary feedwater nozzles, and feedwater j-tubes.

## VEGP Response:

EROSION

Loss of material due to erosion is caused by the action of fluids or fluid-suspended particulate matter on a metal surface. For the VEGP feedwater and auxiliary feedwater nozzles, loss of material due to erosion has been evaluated and found to be not significant. Design of the steam generators, including the use of thermal sleeves, essentially eliminates erosion as an aging effect for these components.

However, SNC notes that FAC is considered to be a plausible degradation mechanism for the feedwater nozzles.

Loss of material due to erosion of carbon steel feedwater J-tubes has been observed in the industry and is a significant aging effect requiring management for that material. However, the VEGP feedwater J-tubes are fabricated from nickel alloy (Alloy 600) which provides superior resistance to erosion as compared to carbon steel. As a result, erosion is not considered to be an applicable degradation mechanism. Regardless, the VEGP J-tubes are included in the scope of the VEGP Steam Generator Program for Upper Internals as a conservative measure.

These conclusions are supported by industry operating experience and by WCAP-14757, *Westinghouse Aging Management Evaluation for Steam Generators*, which indicates that erosion is not significant for feedwater inlet nozzles, and is being addressed in the current licensing basis for the J-tubes.

WEAR

Loss of material due to wear is the removal of surface material due to relative motion between surfaces or under the influence of hard, abrasive particles. Relative motion can be created by thermal movement, vibration, or dynamic effects such as hydraulic transients. For VEGP, the feedwater and auxiliary feedwater nozzles, and feedwater J-tubes are not susceptible to wear because there are no other components in close enough proximity to cause surface contact due to relative motion. Also, wear caused by impact of hard, abrasive particles is not plausible due to the high quality of the feedwater.

This conclusion is supported by industry operating experience and by WCAP-14757, *Westinghouse Aging Management Evaluation for Steam Generators*, which indicates that wear is not applicable for these components.

## AMR Audit - 3.1-17

In LRA Table 3.1.1, line-item 3.1.1-80, in the discussion column, the applicant of states that the bottom mounted instrumentation column cruciforms are the only austenitic stainless steel castings used in the VEGP reactor vessel internals. For these castings, VEGP will manage loss of fracture toughness due to thermal aging and neutron irradiation embrittlement with the LRA B.3.24 AMP, Reactor Vessel Internals Program (RVI). GALL Report Table 1, line-item 80 recommends using Thermal Aging Neutron Irradiation Embrittlement of CASS Program for managing loss of fracture toughness due to thermal aging and neutron irradiation embrittlement.

a. Provide technical justification for using RVI in lieu of the GALL Report recommended program
b. Discuss in details the MRP activities that refer or include loss of fracture toughness due to thermal aging and neutron irradiation embrittlement for the reactor internals.

## VEGP Response:

See the VEGP response to Audit Question B.3.5-02.

## AMR Audit - 3.1-18

LRA Tables 3.1.2-1 through 3.1.2-5 credit Water Chemistry Control Program for managing loss of material aging effect for many components exposed to borated water. LRA shows consistency with GALL Report Volume 2 line-items IV.A2-25, IV.B2-32 and IV.C2-15, which roll up to GALL Report Table 1 item 83. For the following items, provide bases for using Water Chemistry Control Program alone and explain how effectiveness of water chemistry is verified.

a. Table 3.1.2-1, items 2b, 9b, 17b, and 26b
b. Table 3.1.2-2, items 9b and 10b
c. Table 3.1.2-5, items 13a, 14b, 15b, 16b, 17b, 19a, 22b, 27b, 29a, and 30b

## VEGP Response:

The component items referenced in audit question 3.1-18 items a, b, and c are fabricated from austenitic stainless steels, nickel alloys (thermally treated Alloy 600 and or Alloy 82 / 182 weld metals), and low alloy steel clad with either stainless steel or nickel alloy weld metal. For all of these components, the material exposed to the borated water environment is an austenitic, corrosion resistant material. While these materials are potentially susceptible to pitting in off-normal chemistry conditions, the reducing conditions maintained by the VEGP Water Chemistry Control Program have been shown to be adequate to prevent significant localized corrosion. The VEGP Water Chemistry Control Program (see LRA Section B.3.24) is implemented consistent with the EPRI water chemistry guidelines for PWR primary and secondary water chemistry These guidelines implement action levels to limit chemistry excursions which could result in degradation. At VEGP, significant chemistry excursions result in the initiation of a Condition Report to document the off-normal chemistry conditions, evaluate the consequences, and implement appropriate corrective actions. This program is implemented consistent with NUREG-1801 Rev. 1 Section XI.M2.

Additionally, NUREG/CR-6923 documents an extensive degradation study sponsored by the NRC Office of Nuclear Reactor Regulation. This study concludes that loss of material due to corrosion is not a significant concern for stainless steel or nickel alloy materials exposed to a borated water environment. This conclusion is consistent with the VEGP position.

Finally, as noted by the staff in the audit question, NUREG-1801 Rev. 1 Items IV.A2-14, IV.B2-32, and IV.C2-15 are consistent with the VEGP position.

## AMR Audit - 3.1-20

LRA Tables 3.1.2-1, 3.1.2-3, 3.1.2-4, and 3.1.2-5 lists components fabricated from nickel alloy or stainless materials that are exposed externally to air-indoor environment. It appears that exposure to the borated water, leakage from these components or other components in the vicinity of these components, is a plausible environment for these components. For the following LRA line-items explain why "Borated Water (Exterior)" environment is not considered:

a. Table 3.1.2-1 items 3c, 10c, 13c, 15c, and 18c
b. Table 3.1.2-3 items 3e, 4c, 7e, 8d, 11c, 16a, 20e, and 21d
c. Table 3.1.2-4 items 2d, 3d, 4d, 6d, and 7d
d. Table 3.1.2-5, items 15c, 16c, 17c, and 18

## VEGP Response:

The components in the items cited in this question are exposed to an "Air - Indoor (Exterior)" environment. A "Borated Water (Exterior)" environment is not applicable because that is a fluid environment, not an air environment.

The effects of borated water leakage on components in the scope of license renewal were considered in the VEGP AMR evaluations. In the VEGP LRA methodology, components in an air environment which are both susceptible to boric acid corrosion and are located in an area where borated water leakage is plausible had an environment stressor of "(Borated Water Leakage)" included in the environment column. See LRA Table 3.1.2-1, item 14c for an example. For components constructed from materials which are known to be impervious to boric acid corrosion, the "(Borated Water Leakage)" stressor was not used because it did not affect the results of the AMR evaluation. Throughout the VEGP LRA, line items listing "None" for aging effects were included in the Table 2 for a system only when there were no other line items for that component. Therefore, a stainless steel component that has no aging effects in an Air - Indoor environment would not also have a second line listing no aging effects in an Air - Indoor (Borated Water Leakage) environment, or a third line listing no aging effects in an Air - Indoor environment where the component surface temperature is greater than 212°F. The redundant lines were not included for brevity.

## AMR Audit - 3.1-21

LRA Table 3.1.2-3, items 2c, 8d, 20b, 24b, 25b, 31b, and 32b, address alloy steel steam generator components in "Air - Indoor (Exterior) (T > 212 °F)" environment. LRA uses a standard Note G and a plant special Note 106. Note G means that environment not in GALL Report for this component and material, and Note 106 states that "Revision 1 of NUREG-1801[GALL Report] Vol. 2 does not include an external surfaces environment with operating temperatures exceeding 212 °F. External surfaces operating at temperatures above this threshold drive off moisture and preclude corrosion of the component external surfaces. Additionally, borated water leakage is not a concern for this location."

a. Explain how external surfaces of these components remain above 212°F all the time (during reactor operation and shutdown)
b. Provide technical bases for identifying no aging effect for the associated line-items

## VEGP Response:

a.) The external surfaces of the steam generator (SG) components identified in Table 3.1.2-5 as items 2c, 8d, 20b, 24b, 25b, 31b, and 32b (auxiliary feedwater nozzle; feedwater inlet nozzle; secondary side manways, handholes, and covers; steam outlet nozzle; trunions - upper and lower; upper head; and upper shells, lower shells, and transition cones, respectively) are not subject to aging effects requiring management because the external surfaces' operating temperature normally exceeds 212 °F. External surfaces operating at temperatures above this threshold drive off moisture and preclude corrosion of the component external surfaces. VEGP is a base loaded plant and normally operates at full power (external SG surface T>212 °F) during the 18 month refueling cycle. A typical refueling outage is approximately 4 to 6 weeks during which time the external surfaces of the steam generators become ambient temperature. Since the external surfaces of the steam generators are exposed to ambient temperatures for relatively short periods of time, corrosion due to atmospheric moisture is not expected to be significant. Plant and industry operating experience supports this conclusion - see below.

b.) Corrosion due to borated water leakage (boric acid corrosion - BAC) is the other aging effect that could potentially require aging management for the external surfaces of the steam generator components listed in (a) above. The steam generator components listed in (a) above are not located beneath any potential source of borated water leakage and are therefore not subject to BAC.

Operating experience (OE) for the steam generators has not indicated any significant problems with corrosion of external surfaces. VEGP-LR-OER-02, "Mechanical Operating Experience Report for Vogtle Electric Generating Plant License Renewal", identifies an industry issue concerning boric acid deposits from pressure boundary leakage at a steam generator bowl drain line weld. NRC IN 2005-02, "Pressure Boundary Leakage Identified on Steam Generator Bowl Drain Welds", informed licensees of cracking and leakage indications in Alloy 600 steam generator bowl drain welds at Catawba. Boric acid deposits from pressure boundary leakage were identified at a steam generator bowl drain of Alloy 600 material, which is known to be susceptible to primary water stress corrosion cracking (PWSCC). VEGP responded that a Bare Metal Visual (BMV) inspection was performed in the Unit 1 12th refueling outage in 2005 on all 4 steam generator bowl drains but no indications of leakage were detected. A white substance was noted on the drain lines and samples were evaluated but no evidence was found that the white substance was from an active boric acid leak. The substance had been present at the location for many years, most likely boric acid residue originating from activities involving removing the steam generator primary manways. A BMV inspection of the bowl drains was likewise performed on the Unit 2 steam generators in 2005 and no

leakage was found. As on Unit 1, a white substance was noted on the drain lines and samples of the substance were evaluated but no evidence was found that the white substance was from an active boric acid leak. Indications of 1/16" were found, but following a technical evaluation, were determined to be nonrelevant based on the governing ASME code. Any potential boric acid leakage from the bowl drains could not affect the components listed in (a) above because they are well above the bowl drains which are physically located at the very bottom of the channel heads and on the SG vertical centerline. No other industry or actual VEGP operating experience has indicated a trend in degradation of external steam generator surfaces due to corrosion from either atmospheric moisture or boric acid leakage.

## AMR Audit - 3.1-22

LRA Table 3.1.2-1, item 15b, credits Water Chemistry Control and One-Time Inspection Programs for managing loss of material aging effect for nickel alloy leakage monitoring tube assembly in "Air - Indoor (Interior) (wetted)" environment. LRA uses a standard Note G, which means environment not in GALL Report for this component and material. Please provide technical justification for the adequacy of these programs to manage the aging effect

## VEGP Response:

SNC credits the Water Chemistry Control Program and the ISI Program, not a one-time inspection, to manage loss of material associated with the nickel alloy leakage monitoring tube assembly.

Regardless, SNC notes that these leakage monitoring tubes are normally dry. Exposure to coolant only occurs in the event of a leak from the vessel inner o-ring. Water Chemistry Program controls ensure that coolant contacting the leakage monitoring tube assembly is low in detrimental ionic species (e.g. chlorides, sulfates) and as such significant corrosion is not promoted. The ISI Program includes visual examination of the flange surfaces and leak-off region for indications of corrosion. Any indications of leakage or corrosion would result in initiation of a Condition Report and implementation of appropriate corrective actions.

To date, there has been no VEGP or domestic PWR experience associated with degradation of this assembly.

## AMR Audit - 3.1-23

LRA Table 3.1.2-2, item 9d, addresses stainless steel flux thimble tubes in "Air - Indoor (Interior)" environment. LRA uses a standard Note G, which means environment not in GALL Report for this component and material. LRA does not identify an aging effect for this component, material and environment. Therefore, no aging management program is required.

a. Explain why this environment is not considered as a "wetted" environment
b. Provide technical bases for identifying no aging effect for the associated line-item

## VEGP Response:

a. The flux thimble tubes are movable tubes that are inserted into the fixed flux thimble guide tubes from the seal table. When fully inserted, the flux thimble tubes extend from the seal table, through the flux thimble guide tubes, through the lower support structure and the lower core plate, and into the instrumentation tubes of the fuel assemblies at the applicable core locations. The flux thimble tubes form part of the RCS pressure boundary. The external surfaces of the flux thimble tubes are exposed to borated water. The internal surfaces of the flux thimble tubes are dry. The VEGP LRA identifies this environment as "Air - Indoor." This environment is not considered to be "wetted" because there is no source of water that could accumulate in the flux thimble tubes.

b. The VEGP LRA does not identify any aging effects for the material and environment combination of stainless steel exposed to air - indoor (internal). This conclusion in LRA Table 3.1.2-2, item 9d, is identical to the conclusion reached in GALL Table IV.E, item IV.E-2 for the material and environment combination of stainless steel exposed to air - indoor (external). The fact that the flux thimble tubes have the air - indoor environment as the internal environment instead of the external environment has no affect on the conclusion regarding aging effects for this material and environment combination.

   Appendix D of EPRI report 1010639, *Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools*, evaluates stainless steel exposed to an internal air environment. This report concludes that there are no aging effects for stainless steel exposed to an air environment that is not wetted.

   Two decades of operating experience at PWRs throughout the industry confirm that the only significant aging effect for flux thimble tubes is wear of the external surfaces, which is addressed in LRA Table 3.1.2-2, item 9c.

   Therefore, the conclusion that there are no aging effects for stainless steel flux thimble tubes exposed to an air - indoor (internal) environment is based on industry guidance that is supported by extensive operating experience, and which has been acknowledged by incorporation into the GALL Report.

## AMR Audit - 3.1-24

LRA Table 3.1.2-1, item 26c, identifies loss of material due to wear as an aging effect for stainless steel vessel head thermal sleeves exposed to borated water. LRA credits Reactor Vessel Internals Program, which is based on a set of implementation commitments, for managing this aging effect. The applicant has added this combination of component, material, environment, and aging effect to the scope of this program, since this combination is not included in the GALL Report. LRA uses a standard Note H, which means Aging effect not in GALL Report for this component, material, and environment combination. The staff notes that the GALL Report items IV.B2-26 and IV.B2-34 recommend using ISI program for managing loss of material due to wear for Class 1 components fabricated from stainless steel and exposed to reactor coolant. Explain how LRA item 26c differs from the GALL Report IV.B2-26 and IV.B2-34, and why the ISI program is not used for managing loss of material due to wear as an aging effect for stainless steel vessel head thermal sleeves exposed to borated water.

## VEGP Response:

See the VEGP response to Audit Question B.3.24-2 for a summary of the reactor vessel head thermal sleeve wear identified at VEGP.

SNC did not believe that linkage to items IV.B2-26 or IV.B2-34 was appropriate for two reasons:

First, the reactor vessel head thermal sleeve component is not specifically considered in NUREG-1801.

Second, the significant, flow-induced nature of the wear indications on the VEGP reactor vessel head thermal sleeves is considered to be substantially different than the wear issues postulated in NUREG-1801 items IV.B2-26 and IV.B2-34. Significant wear of alignment pins and clevis inserts have not been identified in domestic PWRs. Further, the nature of any postulated wear for these components would be a slow developing condition which would be detectable by a single visual examination in each 10-year ISI interval, i.e. not associated with a high-cycle flow-induced mechanism. In contrast, the VEGP reactor vessel head thermal sleeve wear indications were not detected by ISI (rather by incidental detection during insertion of UT probes for examination of the reactor vessel head penetrations). The nature of the inspection results and the likely mechanism (flow inducted oscillations) do not presently allow for a conclusion that ISI Program inspections are adequate to manage this wear issue.

VEGP continues to monitor this issue and will incorporate any ongoing inspection requirements into the VEGP Reactor Vessel Internals Program. As stated in the VEGP response to audit question B.3.24-2, SNC considers this issue to be an emerging current term issue. Existing aging mangement programs are not considered to be sufficient to manage this issue. The Reactor Vessel Internals Program is the vehicle chosen by SNC to ensure wear of the vessel head thermal sleeves is adequately managed during the period of extended operation.

## AMR Audit - 3.1-25

LRA Table 3.1.2-4, item 14a, identifies cracking due to SCC as an aging effect for stainless steel for pressurizer surge and spray nozzles thermal sleeves exposed to borated water. LRA credits Water Chemistry Control Program for managing this aging effect. LRA uses a standard Note J, which means neither the component nor the material and environment combination is evaluated in GALL Report. The staff notes that the GALL Report IV.C2-19 recommends using Water Chemistry and ISI Programs for cracking due to SCC for stainless steel pressurizer components that are exposed to reactor coolant. Explain why LRA item 14a is not aligned with the GALL Report IV.C2-19, and how effectiveness of Water Chemistry Program to prevent cracking due to SCC for pressurizer surge and spray nozzles thermal sleeves is verified. Please provide justification, if you are not crediting the ISI program.

## VEGP Response:

The pressurizer stainless steel thermal sleeve components do not serve a pressure retaining function, but rather function as a thermal barrier to protect the structural alloy steel nozzle components from thermal cycling and associated fatigue damage. While SNC conservatively postulates SCC for the stainless steel thermal sleeves, loss of component function as a SCC is unlikely for a number of reasons.

For VEGP, the thermal sleeves were positioned and then rolled into place. Following the rolling process, an Alloy 82 weld was used to further fix the sleeve to the safe end.

The welds attaching the thermal sleeve to the nozzle are included in the nozzle dissimilar metal weld AMR line item, not the thermal sleeve line item. As a result, the potential for crack initiation is reduced and is, for all practical purposes, limited to the dissimilar metal attachment weld (which is addressed by Table 3.1.2-4 item 6). The other ends of the thermal sleeves are not fixed and are free to expand or contract.

Stainless steels have performed well in the PWR reactor coolant environment. For the surge nozzle and the inside surface of the spray nozzle, water chemistry controls minimize oxygen and halide concentrations in the reactor coolant system and hydrogen overpressure ensures the presence of low electrochemical corrosion potentials. Under these conditions, SCC has not been a concern for stainless steels. Domestic PWR operating experience supports this conclusion.

Cracking in the weld or roll area is not likely to result in movement of the thermal sleeves since they are tightly fit into the nozzle bore. Additionally, the rolling process results in improved resistance to IGSCC by placing the sleeve in a compressed state. Issues with rolling associated with overexpansion of steam generator tubes are not considered to be applicable for this design configuration. Gross structural failure of the thermal sleeve would require extensive degradation and is not considered likely.

As a result, SNC maintains that continued application of chemistry controls by the Water Chemistry Control Program and continued monitoring of industry operating experience is to manage SCC of the VEGP pressurizer thermal sleeves. Operating experience is monitoring through the VEGP Operating Experience Review Program and through participation in EPRI activities supporting maintenance of the EPRI Primary Water Chemistry Guidelines. The EPRI guidelines are living documents that are periodically reviewed and updated to incorporate new operating experience and research data.

## AMR Audit - 3.1-26

LRA Table 3.1.2-5, items 2a and 8a, credit Fatigue Monitoring Program and Inservice Inspection Program for managing cracking due to cyclic loading as an aging effect for alloy steel auxiliary feedwater nozzle and feedwater inlet nozzle exposed to treated water/ steam. LRA uses a standard Note H, which means aging effect is not in GALL Report for this component, material, and environment combination.

The Fatigue Monitoring Program does not inspect for existing or postulated fatigue-initiated cracks, but rather relies on cycle monitoring to assure that the TLAAs on thermal fatigue will remain valid for the period of extended operation.

a. Clarify whether the aging effect "cracking due to cyclic loading" already postulates the initiation of a fatigue-induced crack in these piping components. If so, clarify and justify how the Fatigue Monitoring Program manages cracking due to cyclic loading in these components when the program does not credit any inspections of the components surfaces.
b. Discuss the inspection methods or techniques and frequency of these inspections that are being used to detect, monitor/trend cracking due cyclic loading

## VEGP Response:

See VEGP response to question 3.0-01. As modified by the response to question 3.0-01, LRA Table 3.1.2-5, items 2a and 8a will reference GALL Report item IV.D1-11 that rolls up to GALL Table 1 line 7. SNC will change the aging effect for this item from "Cracking - cyclic loading" to "Cracking - Thermal Fatigue." The aging management program for this item will be changed to be only the Fatigue Monitoring Program. As SNC now understands the staff's intended use of the term "cracking due to cyclic loading" in GALL, VEGP has no components with an aging effect requiring management of "Cracking - cyclic loading." The following discussion addresses each of the lettered portions of the question:

a. The SNC interpretation of "cracking due to cyclic loading" was different than the staff's. As a result, this term will be replaced with the term "Cracking - Thermal Fatigue." SNC does not postulate the pre-existence of a fatigue-induced crack.

b. Component inspections are not performed by the Fatigue Monitoring Program. The program monitors the CUF of those components that require aging management to prevent cracking due to cumulative fatigue damage.

A License Renewal Application amendment is required

## AMR Audit - 3.1-27

LRA Table 3.1.2-5, items 3b and 27d, credit Water Chemistry Control Program for managing loss of material as an aging effect for nickel alloy auxiliary feedwater nozzle thermal sleeve and tube plugs exposed to treated water/ steam. LRA uses a standard Note H, which means aging effect not in GALL Report for this component, material, and environment combination. Please provide technical justification for the adequacy of these programs for managing loss of material as an aging effect for alloy steel auxiliary feedwater nozzle and feedwater inlet nozzle. Explain how effectiveness of Water Chemistry Program for managing loss of material for auxiliary feedwater nozzle thermal sleeve and tube plugs is verified.

## VEGP Response:

In responding to audit question 3.1-27, SNC assumes that the staff intended to request an explanation of the adequacy of water chemistry controls to manage loss of material in the nickel alloy auxiliary feedwater nozzle thermal sleeve (Table 3.1.2-5 item 3b) and in steam generator tube plugs (Table 3.1.2-5 Item 27d).

Both the auxiliary feedwater thermal sleeve and tube plugs are fabricated from thermally treated Alloy 600. While this material is potentially susceptible to pitting in off-normal chemistry conditions, the reducing conditions maintained by the VEGP Water Chemistry Control Program have been shown to be adequate to prevent significant localized corrosion. The VEGP Water Chemistry Control Program (see LRA Section B.3.24) is implemented consistent with the EPRI water chemistry guidelines for PWR primary and secondary water chemistry These guidelines implement action levels to limit chemistry excursions which could result in degradation. At VEGP, significant chemistry excursions result in the initiation of a Condition Report to document the off-normal chemistry conditions, evaluate the consequences, and implement appropriate corrective actions. This program is implemented consistent with NUREG-1801 Rev. 1 Section XI.M2.

Additionally, NUREG/CR-6923 documents an extensive degradation study sponsored by the NRC Office of Nuclear Reactor Regulation. This study concludes that loss of material due to corrosion is not a significant concern for nickel alloy materials exposed to primary or secondary water environments. This conclusion is consistent with the VEGP position.

Finally, NUREG-1801 Rev. 1 Section IV.D1, "Steam Generator (Recirculating)" implies that localized corrosion of nickel alloys exposed to primary or secondary water is not a significant concern to the staff because there are no line items to address this material, environment, and aging effect combination. Appropriately, the staff focuses on more significant issues, e.g. stress corrosion cracking.

## AMR Audit - 3.1-28

LRA Table 3.3.2-27, item 5k ,credits Water Chemistry Control Program and One-Time Inspection Program for managing cracking for nickel alloy piping component exposed to borated water with T > 140°F. LRA claims consistency with the GALL Report IV.C2-13, which rolls up to GALL Table 1, line-item 31. LRA uses a standard Note E, which means Consistent with GALL Report for material, environment, and aging effect, but a different aging management program is credited. GALL Report IV.C2-13 recommends using Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components, and Chapter XI.M2, "Water Chemistry" for PWR primary water and comply with applicable NRC Orders and provide a commitment in the FSAR supplement to implement applicable (1) Bulletins and Generic Letters and (2) staff-accepted industry guidelines. Please provide technical justification for using Water Chemistry Control Program and One-Time Inspection Program in lieu of the GALL Report recommended programs.

## VEGP Response:

The nickel alloy piping component identified in the request is part of the NSSS Sampling system. The specific piping components are part of the sample coolers which have attached Incoloy 600 tubes for sampling connections. These sample coolers are part of the system No. 1212 that is connected to the Class 2 portion of the RCS, 1201. The coolers are in the Non-Nuclear Safety (Class 424) portion of the system. Thus, these coolers are not within the scope of the ISI program. Water Chemistry Control and a One-Time Inspection have been credited to manage SCC in these nickel alloy components in lieu of Inservice Inspection and Water Chemistry Control.

## AMR Audit - 3.1-29

GALL Report Table 1, item 86 lists stainless steel piping, piping components, and piping elements exposed to air-indoor uncontrolled (external), air with borated water leakage, concrete or gas. GALL Report IV.E-2, IV.E-3, IV.E-4, and IV.E-5 roll up to this table 1 item 86. LRA Table 3.1.1, line-item 3.1.1-86, in the discussion column, states that this line-item is consistent with the GALL Report. However, LRA Table 3.1.2-1 through Table 3.1-2-5 do not include stainless components exposed to air with borated water leakage (IV.E-3), concrete (IV.E-4), or gas (IV.E-5). Please clarify whether these line-items are not applicable to VEGP.

## VEGP Response:

As applicable to the VEGP Reactor Vessel, Reactor Coolant System and Connect Lines, Pressurizer, and Steam Generator Systems, SNC provides the following clarifications:

Exposure of stainless steel surfaces to borated water leakage is applicable for VEGP. However, VEGP LRA Tables 3.1.2-1, 3.1.2-2, 3.1.2-3, 3.1.2-4, and 3.1.2-5 do not include separate items for exposure to borated water leakage. Regardless, VEGP AMR results are consistent with NUREG-1801 item IV.E-4 and conclude that there are no aging effects requiring management for stainless steel component external surfaces, even when exposed to borated water leakage.

VEGP Reactor Coolant System and Connect Lines interface with concrete at wall penetrations. The VEGP AMR methodology does not generate separate AMR line items to address the concrete environment for piping penetrations. In these cases, the environment associated with pipe penetrations is considered to be a part of the air - indoor environment. Regardless, the VEGP AMR results are consistent with NUREG-1801 item IV.E-4 and conclude that there are no aging effects requiring management for stainless steel components embedded in concrete.

VEGP non-ASME Class 1 piping components associated with the Reactor Coolant System and Connect Lines include exposure to a dried gas environment. However, VEGP did not directly link to Table 3.1.1 item 86 because these components are not ASME Class 1. The NUREG-1801 Volume 2 item used in the VEGP LRA is VII.J-19, associated with non-ASME Class 1 mechanical auxiliary systems. SNC believes this match more appropriately describes the component type, since Section IV of NUREG-1801 is focused on ASME Class 1 components. The VEGP AMR conclusion is consistent with NUREG-1801 (either item VII.J-19 or item IV.E-5).

## AMR Audit - 3.1-30

LRA Table 3.1.2-1 item 15a credits Water Chemistry Control Program, Inservice Inspection Program, and Nickel Alloy Management Program for Non-RVCH Penetration Locations for managing cracking due to SCC for nickel alloy leakage monitoring tube assembly in "Air - Indoor (Interior) (wetted)" environment. LRA uses a standard Note F, which means material not in the GALL Report for this component. Please provide technical justification for the adequacy of these programs.

## VEGP Response:

The nickel alloy leakage monitoring tube assembley is connected to the reactor vessel flange and provides a path to route any reactor coolant leakage from the vessel flange to the reactor coolant drain tank. The leakage piping is normally dry unless leakage from the vessel flange exists; thus, its internal environment is air-indoor and wetted due to reactor coolant leakage. Since this tubing material is nickel alloy that is exposed to reactor coolant environemnt, SCC is considered an applicable aging effect for this component.

The VEGP Water Chemistry Control Program is an existing program that mitigates loss of material, cracking, and reduction in heat transfer in system components and structures through the control of water chemistry. The program includes control of detrimental chemical species and the addition of chemical agents. VEGP Procedure 35110-C Tables 1, 3, and 7 list threshold values for detrimental contaminants and specify control parameters for additives. Concentrations are maintained consistent with the EPRI PWR Primary Water Chemistry Guidelines. The VEGP Water Chemistry Control Program currently is in conformance with Revision 5 of the EPRI PWR Primary Water Chemistry Guidelines. The EPRI guidelines (EPRI TR-105714) for PWR primary water chemistry recommend that the concentration of chlorides, fluorides, sulfates, lithium, and dissolved oxygen and hydrogen are monitored and kept below the recommended levels to mitigate SCC of austenitic stainless steel, Alloy 600, and Alloy 690 components. include appropriate corrective actions to be taken when primary water chemistry parameters exceed EPRI Action Levels. Increased sampling is utilized, when appropriate.

The leakage monitoring tube assembly is included in the ISI program. Inspection of the leakage monitor tube is performed in accordance with the ASME Section XI Code as implemented by the VEGP Inservice Inspection Program. Currently, this location is examined by VT-2 at each refueling outage.

The Nickel Alloy Management Program for Non-Reactor Vessel Closure Head Penetration Locations is a plant-specific program that will manage cracking due to PWSCC for non-reactor vessel head nickel alloy component locations. The Nickel Alloy Management Program for Non-Reactor Vessel Closure Head Penetration Locations will manage cracking due to PWSCC for the following nickel alloy components including the Reactor Vessel Flange Leakage Monitor Tube.

Preventive and mitigative actions are an important aspect of the Program. The overall goal of the Program is to maintain plant safety and minimize the impact of PWSCC on plant availability through assessment, inspection, mitigation, and repair or replacement of susceptible components. Methods used for mitigation of susceptible locations may be implemented by the program. For the period of extended operation, the inspection plan will be submitted to the staff for review and approval not less than 24 months prior to entering the period of extended operation for VEGP Units 1 and 2. Mitigation strategies credited by the program for the period of extended operation will be addressed in this submittal.

Detection of PWSCC is currently accomplished by means of various NDE techniques including UT, eddy current testing, bare metal visual examination, and VT-2 examination. Acceptance criteria is

established consistent with the requirements of ASME Section XI as implemented in accordance with 10- CFR 50.55a or NRC approved alternatives.

Inspection locations, inspection frequencies, and inspection methods may change based on new lab data, operating experience, and updated industry guidance. The program will incorporate updated information. For operation in the period of extended operation, SNC will continue to participate in industry initiatives directed at resolving PWSCC issues, such as owners group programs and the Electric Power Research Institute Materials Reliability Program and will submit a program inspection plan to the NRC staff for VEGP not less than 24 months prior to entering the period of extended operation for VEGP Units 1 and 2.

## AMR Audit - 3.1-31

LRA Table 3.1.2-5 credits Water Chemistry Control Program and Steam Generator Tubing Integrity Program for managing loss of material aging effect for nickel alloy steam generator anti-vibration bars (1b) and stainless steel tube support plates and flow distribution baffles (28b) exposed to treated water/steam. Similarly, LRA Table 3.1.2-5 items 9b and 10b credit Water Chemistry Control Program and Steam Generator Program for Upper Internals for managing loss of material as an aging effect for nickel alloy feedwater inlet nozzle thermal sleeve and J-tubes exposed to treated water/ steam. LRA uses a plant special Note H, which means that aging effect not in GALL Report for this component, material, and environment combination. Please provide bases for identifying this aging effect and using Water Chemistry Control Program and Steam Generator Tubing Integrity Program or Steam Generator Program for Upper Internals for the assoicated AMR line-items.

## VEGP Response:

Loss of Material due to general corrosion is typically only associated with carbon steels which do not develop tightly adherent oxidation layers in the SG coolant or borated water leakage environments. Stainless steels and nickel base alloys are protected by passive oxidation layers. For alloy steels, stainless steels, and nickel base alloys, localized corrosion in the form of crevice corrosion or pitting is the primary corrosion mode. While a macroscopic geometrical crevice determines the site of corrosion in crevice corrosion, a microscopic topographic feature such as surface dislocations, defects, etc. determine the site of pitting. However, SNC has conservatively include loss of material as an aging effect for nickel alloy and stainless internal components exposed to treated water/steam.

The Inservice Inspection Program, Steam Generator Program for Upper Internals, Steam Generator Tubing Integrity Program, and Water Chemistry Control Program are all credited for management of loss of material.

The VEGP Water Chemistry Control Program is an existing program that prevents or mitigates loss of material, cracking, and reduction in heat transfer in system components and structures through the control of water chemistry. The program includes control of detrimental chemical species and the addition of chemical agents. The EPRI Primary Water Chemistry Guidelines and Secondary Water Chemistry Guidelines form the basis for the program. The VEGP Water Chemistry Control Program includes periodic monitoring and control of detrimental contaminants such as chlorides, fluorides, dissolved oxygen, and sulfate concentrations.concentrations below the levels known to result in loss of material.

The VEGP Steam Generator Tubing Integrity Program will provide reasonable assurance that the steam generator tubes will perform their intended safety function(s) during the period of extended operation. Monitoring of secondary side components, such as the tube supports, is conducted as part of the Steam Generator Secondary-Side Integrity Plan.

Prior to each SG tubing inspection, a degradation assessment (DA) is performed by SNC in accordance with SG Program Requirements. The purpose of the DA is to determine and document inspection plans prior to the inspection with respect to degradation mechanisms which could potentially occur. The DA establishes the inspection scope, NDE techniques, tube structural limits and flaw growth rates or how it is determined. It provides assurance that Non-Destructive Examination (NDE) (i.e. eddy current) detection and sizing performance are known. The VEGP SGTIP is credited to manage degradation of:

- Anti-Vibration Bars
- Stayrod Assemblies

- Tubes (U-Tubes) and Tube Plugs
- Tube Bundle Wrapper and Support Assembly
- Tubeplate
- Tube Support Plates, Flow Distribution Baffles

Review of recent VEGP Steam Generator Program performance results show that the program has been effective in finding and correcting degradation attributable to aging effects requiring management.

## AMR Audit - 3.1-32

LRA Table 3.1.2-3 item 5a identifies cracking due to SCC as an aging effect for carbon steel RCP motor oil coolers channel head exposed to close-cycle cooling water. LRA credits Auxiliary Component Cooling Water (ACCW) System Carbon Steel Components Program, which is based on a new plant specific program, for managing this aging effect. The applicant has added this combination of component, material, environment, and aging effect to the scope of this program, since this combination is not included in the GALL Report. Please provide technical justification for the adequacy of this program.

## VEGP Response:

Per the system boundary for the reactor coolant system the RCP motor oil coolers are part of the RCS boundary, 1201. The RCP motor coolers channel head are exposed to the closed-cycled cooling water which is provided from the Auxiliary Component Cooling Water (ACCW) System. Since the oil coolers are tagged as 1201, RCS, the coolers are scoped in the boundary for the RCS.

RCP Lower Lube Oil Cooler 1-1201-P6-003-E01 has ACCW cooling water on tube side and lube oil on shell side per P&ID 1X4DB138-2. In-scope piping is connected to the channel head flanges, so only the channel head and shell are included to maintain the intended function of the base mounted component. Channel head and shell materials are conservatively assumed to be CS since could not be verified per vendor information. At VEGP, operating experience indicates that SCC has been an issue of concern for only the Unit 2 ACCW system. Conservatively, SNC includes SCC of carbon steels in nitrite CCW for both the Unit 1 and Unit 2 ACCW systems. Other systems have not had a history of SCC. The LRA credits the ACCW System Carbon Steel Components Program for managing the aging effects of SCC of the RCP motor coolers channel head.

The ACCW System Carbon Steel Components Program is a new plant-specific program. The program manages cracking of carbon steel components exposed to auxiliary component cooling water through a combination of leakage monitoring and routine and periodic inspections. The program is in response to operating experience related to nitrite induced stress corrosion cracking (SCC) and subsequent component leakage in the VEGP Auxiliary Component Cooling Water (ACCW) System components. The scope of this program is for carbon steel components exposed to auxiliary component cooling water.

The program includes formalization of some existing VEGP activities and new activities. The program relies upon leakage detection monitoring, routine walkdowns, and periodic visual examinations. Operating experience indicates that ACCW system leaks attributed to nitrite induced SCC are detected and repaired prior to a loss of the system intended function. All leaks have been detected prior to any significant impact on system pressure, flow and integrity. The program also includes preventive measures applicable to repairs and modifications intended to minimize crack initiation sites, lower stresses, and improve inspectability.

The VEGP ACCW System Carbon Steel Components Program will provide reasonable assurance that cracking of ACCW System carbon steel components due to nitrite induced SCC will be adequately managed such that the components included within the scope of this program will continue to perform their intended function during the period of extended operation.

## AMR Audit - 3.2-01

In LRA Table 3.2.1, Item 3.2.1-01, the discussion column states that cracking of metal components due to cumulative fatigue damage is addressed as a TLAA. However, there are no AMR Table 2 line items in Section 3.2, Engineered Safety Features, which refer to this Table 1 item. Please explain why this line item is not used in Table 2 of Section 3.2.

## VEGP Response:

There are no ESF components where cracking -CFD is an aging effect requiring management, therefore there are no line items in Table 3.2.2-1 or Table 3.2.2-2 that reference Item 3.2.1-01 in Table 3.2.1. See the response to question 3.0-01 for a more complete explanation of why there are no items in Tables 3.2.2-1 or 3.2.2-2 that reference Item 3.2.1-01 in Table 3.2.1.

## AMR Audit - 3.2-02

In LRA Table 3.2.1, Item 3.2.1-10, the discussion column states that VEGP AMR results do not include stainless steel heat exchanger tubes exposed to treated water (non-borated). Then in LRA Section 3.2.2.2.4 (2), which is referred to in the discussion column for Table 3.2.1, Item 3.2.1-10, the LRA further states that the VEGP AMR results do not predict reduction in heat transfer for heat exchanger tubes exposed to borated water. Please clarify, whether the LRA is declaring that there is no reduction in heat transfer aging affect for heat exchanger tubes exposed to borated water or that there are no components of this type exposed to borated water. If the LRA is declaring that this aging effect is not present, please justify its exclusion.

## VEGP Response:

The VEGP AMR results include stainless steel heat exchanger tubes exposed to borated water. However, the AMR results indicate that reduction of heat transfer due to fouling is not an applicable aging effect for those components.

Fouling is normally associated with macro organisms (such as barnacles, mussels, clams, algae, and others) or with significant amounts of silt or other debris. These can all be present in raw water, but are not expected in borated water. Borated water is filtered to remove particulates, is deionized to remove contaminants, and is low in oxygen content. Biological activity is highly unlikely in the borated water environment. Significant accumulation of corrosion products is also unlikely since all materials in contact with borated water are corrosion resistant.

Heat exchangers exposed to a borated water environment may be susceptible to boron precipitation fouling or scaling. Over time, uncontrolled fouling may prevent the performance of intended functions as a result of loss of heat exchanger performance. The solubility limit of boric acid at 32 °F is approximately 26,600 ppm. The borated water systems containing heat exchangers operate at higher temperatures and substantially lower boric acid concentrations than this solubility limit. Therefore the boric acid will remain in solution and precipitation fouling or scaling is not a concern.

VEGP operating experience does not support an aging effect of reduction of heat transfer due to fouling for stainless steel heat exchanger tubes exposed to borated water.

Therefore, reduction of heat transfer due to fouling is NOT considered to be an aging effect requiring further evaluation in VEGP aging management reviews.

## AMR Audit - 3.2-03

LRA Table 3.2.1, Item 3.2.1-32, is used to manage the loss of material due to general corrosion in steel piping and ducting components and internal surfaces internally exposed to air-indoor uncontrolled. In the discussion column for this Table 1 item, the LRA states that VEGP will manage this aging effect with the One-Time Inspection Program. The GALL Report recommends using an AMP with periodic inspections such as the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components. Please justify the use of the One-Time Inspection Program in light of the GALL Report recommendation. This Table 1 item is used in LRA Tables 3.1.2-3, 3.2.2-2, 3.3.2-5, 3.3.2-6, 3.3.2-19, 3.3.2-20, 3.3.2-23, 3.3.2-29, 3.3.2-32, 3.4.2-2, and 3.4.2-5.

## VEGP Response:

For carbon steel and cast iron exposed to an Air - Indoor (Internal) environment where condensation or wetting are not present, some loss of material due to general corrosion is expected. However, VEGP expects the degree of corrosion for this material and environment combination to be minor and to progress slowly. VEGP believes that a one-time inspection will confirm this expectation, and that additional inspections will not be warranted. If the one-time inspection indicates that corrosion of this material and environment combination has progressed such that the intended function of a component could be affected during the period of extended operation, then the impacted components will be included in the Piping and Duct Internal Inspection Program, or other program as appropriate. Carbon steel and cast iron exposed to condensation, wetting, or Air - Outdoor (Internal) are managed by the Piping and Duct Internal Inspection Program because the potential for exposure to water negates the expectation that corrosion would progress slowly.

## AMR Audit - 3.2-04

In LRA Table 3.2.1, Item 3.2.1-50, the discussion column states that this item is not applicable to VEGP. However, there are AMR line items in LRA Tables 3.3.2-19, 3.3.2-27 and 3.3.2-31 that reference Table 3.2.1, Item 3.2.1-50. Please clarify the statement contained in the discussion column of Table 3.2.1, Item 3.2.1-50. Justify why LRA Table 3.2.1, Item 3.2.1-50 is being used for applicable AMR lines items in these Type 2 AMR Tables for the Auxiliary Systems.

## VEGP Response:

The Table 3.2.1 (Item 3.2.1-50) discussion column incorrectly states that this item is not applicable to VEGP since line items in LRA Tables 3.3.2-19 and 3.3.2-31 reference Table 3.2.1 (Item 3.2.1-50). Table 3.2.1 (Item 3.2.1-50) is used for aluminum alloy piping components in an "Air-Indoor (Interior or Exterior)" environment. No such matching item was found in GALL Volume I, Table 3 for auxiliary systems, therefore these items were linked to an applicable GALL Volume I, Table 2 item for ESF systems. The Table 3.2.1 (Item 3.2.1-50) discussion will be revised to address the auxiliary systems items.

A license renewal application amendment is required.

## AMR Audit - 3.2-05

In LRA Table 3.2.1, Item 3.2.1-57, the discussion column states that this item is consistent with NUREG-1801. However, there are no AMR line items in the LRA Table 2s that reference Table 3.2.1, Item 3.2.1-57. Please clarify the statement contained in the discussion column of Table 3.2.1, Item 3.2.1-57.

## VEGP Response:

LRA Table 3.2.1, Item 3.2.1-57 refers to stainless steel and copper alloy (<15% zinc) exposed to air with borated water leakage. The conclusion of the VEGP AMR process is that there are no aging effects for these material and environment combinations, which is consistent with the GALL conclusion. However, because VEGP did not list multiple lines with no aging effects for a given component (refer to the response to AMR question 3.1-20), this Table 1 item was not used as a reference in the LRA Table 2's. LRA Table 3.2.1, Item 3.2.1-57 will be revised to indicate that this item was not used.

A License Renewal Application amendment is required.

## AMR Audit - 3.2-07

In LRA Table 3.2.1, Item 3.2.1-39, the discussion column states that VEGP manages the aging effect of loss of material in raw water - NSCW environment with the Generic Letter 89-13 Program. However, in Table 3.3.2-27, Sample Baths - Steam Generator Blowdown Bath (Shells) exposed to raw water - well water references this table 1 item but manages the loss of material with the Periodic Surveillance and Preventive Maintenance Activities Program. Please clarify the information provided in the discussion column in Table 3.2.1, Item 3.2.1-39 in light of the above information. Please address the use of the Periodic Surveillance and Preventive Maintenance Activities Program to manage the loss of material due to MIC corrosion and fouling for the Sample Baths - Steam Generator Blowdown Bath (Shells) exposed to raw water - well water. Also address the inspection frequency of the Periodic Surveillance and Preventive Maintenance Activities Program for this component type versus that specified in the Generic Letter 89-13 Program.

## VEGP Response:

The discussion column in LRA Table 3.2.1, Item 3.2.1-39, only addresses the raw water - NSCW environment. A discussion of the raw water - well water environment was omitted. This discussion column will be revised as shown below:

EXISTING

"Consistent with NUREG-1801 with aging management program exception.

VEGP manages the aging effect of loss of material in the raw water - NSCW environment with the Generic Letter 89-13 Program (Appendix B.3.12)."

REVISED

"Consistent with NUREG-1801 with aging management program exception for the raw water - NSCW environment. VEGP manages the aging effect of loss of material in the raw water - NSCW environment with the Generic Letter 89-13 Program (Appendix B.3.12).

Different than NUREG-1801 for components exposed to the raw water - well water environment. VEGP manages loss of material in the Steam Generator Blowdown Sample Bath (Shells) exposed to raw water - well water with the Periodic Surveillance and Preventive Maintenance Activities (Appendix B.3.21)."

The safety related components managed by the Generic Letter 89-13 Program are inspected at intervals that have been established to support the VEGP response to NRC Generic Letter 89-13.

The Steam Generator Blowdown Sample Bath Shells are non-safety related components that are in scope for 10 CFR 54.4(a)(2). As discussed in Appendix B.3.21, Periodic Surveillance and Preventive Maintenance Activities, inspections of the Steam Generator Blowdown Sample Bath Shells are new preventive maintenance tasks. The inspection frequency for these components will be established based on the results of the initial inspections such that assurance will be provided that these components will continue to perform their intended function between inspections for the duration of the period of extended operation.

A License Renewal Application Amendment is required.

## AMR Audit - 3.3-01

In LRA Table 3.3.2-5, page 3.3-108, AMR line 6a shows an environment of closed cycle cooling water on the exterior of the CCW heat exchanger tubesheets. Explain how the exterior of the tubesheets can have a closed cycle cooling water environment when the interior of the channel heads have a raw water NSCW environment.

## VEGP Response:

In LRA Table 3.3.2-5, AMR line 6a shows an environment of closed cycle cooling water on the exterior of the CCW heat exchanger tubesheets. For this heat exchanger, the convention was chosen that the shell side of the tubesheet would be designated as the "exterior" and the channel head side would be designated as the "interior". The opposite convention could have just as easily been chosen. Based on the convention chosen and the design of the heat exchanger, the "exterior" of the tubesheet is exposed to an environment of closed-cycle cooling water and the "interior" of the tubesheet is exposed to an environment of raw water - NSCW. Closed-cycle cooling water flows through the shell side (tube external surfaces also) and raw water - NSCW flows through the channel heads (tube internal surfaces also). This convention is consistent with the tube external (closed-cycle cooling water) and internal environments (raw water - NSCW) called out in items 5b and 5c respectively, of Table 3.3.2-5, page 3.3-107.

## AMR Audit - 3.3-02

In LRA Table 3.3.2-5, page 3.3-106, AMR line 1e is identical to AMR line 1d. Explain why this line item is shown twice since the component is identical and also the MEAP.

Also, in LRA Table 3.3.2-6, page 3.3-114, AMR line 1g is identical to AMR line 1e. Explain why this line item is shown twice since the component is identical and also the MEAP

## VEGP Response:

In LRA Table 3.3.2-5, page 3.3-106, AMR line 1e is identical to AMR line 1d. This is in error and one of these line items will be removed from Table 3.3.2-5.

Also, in LRA Table 3.3.2-6, page 3.3-114, AMR line 1g is identical to AMR line 1e. This is in error and one of these line items will be removed from Table 3.3.2-6.

A License Renewal Application ammendment is required.

## AMR Audit - 3.3-03

In LRA Table 3.3.2-5, page 3.3-109, AMR line 10a has the exterior of the CCW pump motor cooler tubesheets exposed to an air-ventilation environment. Clarify how these tubesheets are exposed to an air-ventilation environment.

## VEGP Response:

The CCW pump motors are totally-enclosed water-cooled motors. Each motor is are cooled by recirculating internal air through a heat exchanger which in turn is cooled by Nuclear Service Cooling Water. Fans internal to the motor circulate the air through the rotor and stator and through the heat exchanger in a closed recirculating loop. The heat exchanger is provided with condensate drains. Because the air is recirculated through the cooler and is dehumidified by draining off any moisture that condenses on the heat exchanger tubes, the air internal to the heat exchanger is considered to be Air - Ventilation.

## AMR Audit - 3.3-04

In LRA Table 3.3.2-10, page 3.3-147, AMR line 30b shows a stainless steel material. This AMR line item references GALL Volume 2 item VII.E1-2 and Table 1 item 3.3.1-51, which is associated with copper alloy material. Please explain why the aging management program associated with this GALL Volume 2 item and Table 3.3.1 item 3.3.1-51 is appropriate for managing the aging effect for this material and environment combination.

## VEGP Response:

LRA Table 3.3.2-10, page 3.3-147, line item 30b, incorrectly shows the Table 1 item as 3.3.1-51 for the CVCS normal charging pump motor cooler tubesheets, which are made of stainless steel, not copper alloy. Line item 30b also incorrectly shows the NUREG-1801 Vol. 2 item as VII.E1-2. The correct Table 1 item is 3.2.1-28 in Table 3.2.1 and the correct NUREG-1801 Vol. 2 item is V.D1-4. There is no change in the GALL consistency statement as a result of this change. Correction will be made to Table 3.3.2-10.

A License Renewal Application amendment is required to correct this discrepancy.

## AMR Audit - 3.3-05

LRA Table 3.2.2-1, Containment Spray System, identifies containment spray pump motor cooler tube's exterior surfaces being managed by Table 3.3.1, item 3.3.1-25, using the External Surfaces Monitoring Program. How is this inspection performed as the AMP does not describe this activity?

## VEGP Response:

LRA Table 3.2.2-1, item 8c, lists the exterior surface of the motor cooler tubes as being managed by the Piping and Duct Internal Inspection Program. Item 8c refers to Table 1, item 3.3.1-25. Table 1, item 3.3.1-25, which is for copper alloy HVAC piping, piping components, and piping elements exposed to condensation (external), states in the discussion column that, depending on the location of the component, VEGP will manage the aging effect with either the External Surfaces Monitoring Program or the Piping and Duct Internal Inspection Program. Further discussion is provided in section 3.3.2.2.10(3). Because the motor cooler tubes are internal to the cooler, in this case the External Surfaces Monitoring Program is not the appropriate program to manage loss of material, and the Piping and Duct Internal Inspection Program was listed as the aging management program for LRA Table 3.2.2-1, item 8c.

## AMR Audit - 3.3-06

Line 6b of LRA Table 3.2.2-2 for the Spent Fuel Pool (SFP) Cooling and Purification System identifies Reduction of Heat Transfer is managed by Closed-Cycle Cooling Water Program for stainless steel SFP Hx Tubes (Exterior). How is loss of material for SFP Tubes exposed to Closed-Cycle Cooling Water managed?

## VEGP Response:

Loss of material from the Spent Fuel Pool Heat Exchanger tubes exposed to closed-cycle cooling water is managed by the Closed Cooling Water Program. This was an inadvertent omission from the LRA. LRA Table 3.3.2-2 will be revised to add item 6c as follows:

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 6c | Heat Exchangers-SFP HXs (Tubes) | Exchange Heat Pressure Boundary | Stainless Steel | Closed-Cycle Cooling Water (Exterior) | Loss of Material | Closed Cooling Water Program | V.A-07 | 3.2.1-28 | B |

A License Renewal Application amendment is required to correct this omission.

## AMR Audit - 3.3-07

Table 3.3.1, item 3.3.1-57, (also applies to 3.3.1-58 and 3.3.1-59) for loss of material in steel components claims consistency with GALL and utilizes the External Surfaces Monitoring Program. In the discussion column however, a note excludes components subject to normal operating temperatures exceeding 212 °F, because moisture does not exist. Please provide the list of components that are excluded from the scope of this AMR line item based on the normal operating temperature exceeding 212 °F.

## VEGP Response:

Table 3.3.1, items 3.3.1-57, 3.3.1-58, and 3.3.1-59, for loss of material in steel components, has a note which excludes components subject to normal operating temperatures exceeding 212 °F, because moisture is driven off. The components having no aging effects requiring management due to this operating temperature are found in Sections 3.1 and 3.4 of the License Renewal Application and are as follows: Section 3.1, Table 3.1.2-5, line items 2c, 8d, 20b, 24b, 25b, 31b, 32b (see VEGP response to RAI 3.1-21); Section 3.4, Table 3.4.2-1, line items 8j, 8l, 9c, 12l, 12n; Section 3.4, Table 3.4.2-2, line items 3e, 3g, 4c, 6e, 6g; Section 3.4, Table 3.4.2-3, line items 8f, 13f; Section 3.4, Table 3.4.2-5, line items 3h, 4e, 5h. Note 106 of Table 3.1.2-5 and note 403 of Tables 3.4.2-1, 3.4.2-2, 3.4.2-3, and 3.4.2-5 is similar to the note of Table 3.3.1 and describes the fact that moisture is driven off by temperatures above 212 °F. Only the above listed components' external surfaces are excluded from the aging effects requiring management due to atmospheric moisture because the normal operating temperature exceeds 212 °F. The note in Table 3.3.1 will be removed because it does not apply to Auxiliary Systems or to any other systems or components not already covered by notes 106 and 403.

A License Renewal Application amendment is required to correct this discrepancy.

## AMR Audit - 3.3-08

Table 3.3.1, item 3.3.1-63, identifies loss of material due to wear as the aging effect and mechanism for steel fire rated doors exposed to air. LRA Table 3.5.2-12, lines 12 and 16 identify plant specific note 504 which states that, although the aging effect is consistent with GALL, the aging mechanism is different. LRA AMP B.3.9 states that doors are managed by periodic inspections. To ensure that periodic inspections are sufficient to manage the steel fire rated doors exposed to air, identify what aging mechanism is responsible for loss of material.

## VEGP Response:

The aging mechanism responsible for the loss of material aging effect identified for this item is wear (Table 3.3.1, item 3.3.1-63). Only the moving components of fire doors incur wear and as such, are considered active, not requiring aging management (examples of active fire door components - hinges and latches). Note 504 indicates that for this item, the aging effect of loss of material matches the GALL item (VII.G-4) but the GALL aging mechanism of "wear" in VII.G-4 does not match SNC's aging management strategy, e.g., active components are not age managed.

The aging mechanism of 'corrosion' is responsible for the aging effect of 'loss of material' for this component. Periodic visual inspections of fire doors are performed for loss of material due to corrosion.

## AMR Audit - 3.3-09

In LRA Table 3.3.2-11, page 3.3-154, AMR line 5b, Table 3.3.1, item 3.3.1-25 is referenced. This Table 1 item recommends a plant specific AMP to be utilized for managing the loss of material due to pitting and crevice corrosion for copper alloy HVAC piping exposed to condensation (external). Please clarify why the Piping and Duct Internal Inspection Program is appropriate for managing loss of material for cooling coils (Essential Chilled Water) exposed to air-ventilation (Exterior).

## VEGP Response:

The Piping and Duct Internal Inspection Program is appropriate for detecting pitting and crevice corrosion in copper alloy HVAC piping exposed to condensation (external). Copper alloys are widely used in cooling coils throughout the industry due in part to their corrosion-resistance.

Pitting and crevice corrosion are detectable prior to any loss of intended function utilizing visual inspections, which will examine for any signs of the following unacceptable conditions:

(i) Evidence of active pitting or progressive crevice corrosion as indicated by active corrosion pits or the buildup of corrosion products at crevice locations, or
(ii) Thick, loose, or wet oxidation layers and associated reduction in the base metal thickness due to the presence of an aggressive environment.

The Piping and Duct Internal Inspection Program is based on periodic inspections, the frequency of which will primarily be determined by operating experience. Inspections will normally be performed concurrent with scheduled preventive maintenance, surveillance testing, and corrective maintenance activities. This enhances the accessibility of normally inaccessible components such as the copper alloy piping, which consists of cooling coils located inside HVAC cooling units.

Therefore, the Piping and Duct Internal Inspection Program is appropriate for inspecting for loss of material due to pitting and crevice corrosion on copper alloy HVAC piping exposed to condensation (external).

## AMR Audit - 3.3-10

In Table 3.3.2-11 on page 3.3-154 of the LRA for AMR line 5a note B is referenced. GALL volume 2 item VII.F1-16 is shown for this AMR line and calls for a plant-specific AMP. Explain why a note B is shown, consistent with GALL with AMP exceptions, instead of note E; GALL identifies a plant-specific AMP. Note: The same logic should apply to line 5a as for line 5b on page 3.3-154. Line 5b has a note E.

## VEGP Response:

It is determined that the Note for AMR line 5a of LRA Table 3.3.2-11 on page 3.3-154 should be Note "E" instead of Note "B" as shown. This change is based on the fact that the GALL volume 2 item VII.F1-16 that matches to the AMR line 5a identifies a plant-specific AMP while the AMP credited in the LRA, External Surfaces Monitoring Program, is a GALL AMP with exceptions. Therefore, a different AMP is credited while the material, environment and aging effect are consistent with NUREG 1801. Thus, a Note "E" should have been specified instead of Note "B".

A license renewal application amendment is required to change Note "B" to note "E".

## AMR Audit - 3.3-11

In Table 3.3.2-11 on page 3.3-155 of the LRA for AMR line 6c note B is referenced. GALL volume 2 item VII.F2-14 is shown for this AMR line and calls for a plant-specific AMP. Explain why a note B is shown, consistent with GALL with AMP exceptions, instead of note E; GALL identifies a plant-specific AMP. Note: The same logic should apply to line 6c as for line 6d on page 3.3-155. Line 6d has a note E.

## VEGP Response:

It is determined that Note "B" for AMR line 6c LRA Table 3.3.2-11 on page 3.3-155 should be Note "E" instead of Note "B" as shown. This change is based on the fact that the GALL volume 2 item VII.F2-14 that matches to the AMR line 6c identifies a plant-specific AMP while the AMP credited in the LRA, External Surfaces Monitoring Program, is a GALL AMP with exceptions. Therefore, a different AMP is credited while the material, environment and aging effect are consistent with NUREG 1801. Thus, a Note "E" should have been specified instead of Note "B".

A license renewal application amendment is required to change Note "B" to note "E".

## AMR Audit - 3.3-12

In Table 3.3.2-12 on page 3.3-159 of the LRA for AMR line 2d note B is referenced. GALL volume 2 item VII.F2-1 is shown for this AMR line and calls for a plant-specific AMP. Explain why a note B is shown, consistent with GALL with AMP exceptions, instead of note E; GALL identifies a plant-specific AMP.

## VEGP Response:

It is determined that Note "B" for AMR line 2d LRA Table 3.3.2-12 on page 3.3-159 should be Note "E" instead of Note "B" as shown. This change is based on the fact that the GALL volume 2 item VII.F2-1 that matches to the AMR line 2d identifies a plant-specific AMP while the AMP credited in the LRA, External Surfaces Monitoring Program, is a GALL AMP with exceptions. Therefore, a different AMP is credited while the material, environment and aging effect are consistent with NUREG 1801. Thus, a Note "E" should have been specified instead of Note "B".

A license renewal application amendment is required to change Note "B" to note "E".

## AMR Audit - 3.3-13

In Table 3.3.2-12 on page 3.3-160 of the LRA for AMR line 4d note B is referenced. GALL volume 2 item VII.F2-1 is shown for this AMR line and calls for a plant-specific AMP. Explain why a note B is shown, consistent with GALL with AMP exceptions, instead of note E; GALL identifies a plant-specific AMP.

## VEGP Response:

It is determined that Note "B" for AMR line 4d LRA Table 3.3.2-12 on page 3.3-160 should be Note "E" instead of Note "B" as shown. This change is based on the fact that the GALL volume 2 item VII.F2-1 that matches to the AMR line 4d identifies a plant-specific AMP while the AMP credited in the LRA, External Surfaces Monitoring Program, is a GALL AMP with exceptions. Therefore, a different AMP is credited while the material, environment and aging effect are consistent with NUREG 1801. Thus, a Note "E" should have been specified instead of Note "B".

A license renewal application amendment is required to change Note "B" to note "E".

## AMR Audit - 3.3-14

In Table 3.3.2-12 on page 3.3-159 of the LRA for AMR line 3c note B is referenced. GALL volume 2 item VII.F2-14 is shown for this AMR line and calls for a plant-specific AMP. Explain why a note B is shown, consistent with GALL with AMP exceptions, instead of note E; GALL identifies a plant-specific AMP. Note: The same logic should apply to line 3c as for line 3d on page 3.3-159. Line 3d has a note E.

## VEGP Response:

It is determined that Note "B" for AMR line 3c LRA Table 3.3.2-12 on page 3.3-159 should be Note "E" instead of Note "B" as shown. This change is based on the fact that the GALL volume 2 item VII.F2-14 that matches to the AMR line 3c identifies a plant-specific AMP while the AMP credited in the LRA, External Surfaces Monitoring Program, is a GALL AMP with exceptions. Therefore, a different AMP is credited while the material, environment and aging effect are consistent with NUREG 1801. Thus, a Note "E" should have been specified instead of Note "B".

A license renewal application amendment is required to change Note "B" to note "E".

## AMR Audit - 3.3-15

In Table 3.3.2-14 on page 3.3-172 of the LRA for AMR line 2c note B is referenced. GALL volume 2 item VII.F2-14 is shown for this AMR line and calls for a plant-specific AMP. Explain why a note B is shown, consistent with GALL with AMP exceptions, instead of note E; GALL identifies a plant-specific AMP. Note: The same logic should apply to line 2c as for line 2d on page 3.3-172. Line 2d has a note E.

## VEGP Response:

It is determined that Note "B" for AMR line 2c LRA Table 3.3.2-14 on page 3.3-172 should be Note "E" instead of Note "B" as shown. This change is based on the fact that the GALL volume 2 item VII.F2-14 that matches to the AMR line 2c identifies a plant-specific AMP while the AMP credited in the LRA, External Surfaces Monitoring Program, is a GALL AMP with exceptions. Therefore, a different AMP is credited while the material, environment and aging effect are consistent with NUREG 1801. Thus, a Note "E" should have been specified instead of Note "B".

A license renewal application amendment is required to change Note "B" to note "E".

## AMR Audit - 3.4-02

GALL Report, Table 4, item 29, identifies aging effect as "wall thinning due to flow- accelerated corrosion" pertaining to carbon steel piping, piping components, and piping elements, for managing flow-accelerated corrosion. However, Table 2 items for this line item in LRA identify the aging effect as "loss of material." Clarify the inconsistency in the LRA.

## VEGP Response:

The VEGP LRA Table 2 items which identified flow-accelerated corrosion (FAC) as an applicable aging mechanism list "Loss of Material - FAC" as the aging effect requiring management. While the terminology is somewhat different, loss of material due to flow-accelerated corrosion as identified in the VEGP LRA is identical to wall thinning due to flow-accelerated corrosion as listed in GALL Volume 1, Table 3.4-1, item 29. Wall thinning occurs as material is removed from the interior surface of a component by the corrosive effects of the water flowing over the surface. The aging effects are consistent between GALL and the VEGP LRA.

## AMR Audit - 3.4-03

LRA Table 3.1.2-3 items 7d and 20d credit Water Chemistry Control Program and One-Time Inspection Program for managing loss of material aging effects for stainless steel piping components and valves bodies in the reactor coolant system exposed to treated water. LRA claims consistency with the GALL Report VIII.B1-4 that rolls up to Table 3.4.1-16. GALL Report VIII.B1-4 is for piping and piping components and elements in the main steam system. LRA uses a standard Note A, which means LRA line-item is consistent with GALL Report item for component, material, environment, aging effect, and the AMP. Please explain how LRA items 7d and 23d are consistent with the GALL Report VIII.B1-4. Also, provide technical justification for adequacy of the One-Time Inspection Program for detection of loss of materials for the reactor coolant system piping and valves bodies.

## VEGP Response:

LRA Table 3.1.2-3 items 7d and 20d are included in the RCS boundary as attached piping per scoping criteria (a)(2). These piping components and valve bodies are shown on LR Boundary 1/2X4DL112 and function to supply reactor makeup water to the pressurizer relief tank. The safety classes of the components described in VEGP Table 3.1.2-3 items 7 and 20 are ASME Safety Class 2 and Non-Nuclear Safety, NOT ASME Safety Class 1.

Reactor makeup water is essentially demineralized water and is defined by the VEGP AMR process as a "treated water."

Since these AMR items describe non-ASME Class 1 piping components fabricated from stainless steel and exposed to a treated water environment, these items were considered a match to GALL Report item VIII.B1-4. The VEGP aging management approach is also a match to item VIII.B1-4, water chemistry control and a one-time verification. As a result, standard Note A applies.

Additionally, SNC notes that ASME Safety Class 1 components are identified as such in Table 3.1.2-3.

## AMR Audit - 3.4-04

LRA Table 3.4.2-1, Items 2b, 7b, and 12b, credit External Surfaces Monitoring Program for managing loss of material aging effects for aluminum alloy ARV local actuator filter housings, ARV local actuator oil reservoir filler/breather caps, and valve bodies in the main steam system exposed to an air - outdoor (exterior) environment. LRA claims consistency with the GALL Report III.B2-7 that rolls up to Table 3.5.1-50. For these AMR items, provide your basis why the External Surfaces Monitoring Program will be capable of managing loss of material in these components in lieu of VEGP Structures Monitoring Program as specified in the GALL Report. As part of this basis, clarify whether or not any exceptions taken in your External Surfaces Monitoring Program against the recommended program elements in GALL AMP XI.M36, External Surfaces Monitoring," are applicable to the AMRs for these components, and if so, justify why these exceptions are acceptable to manage loss of material in these components.

## VEGP Response:

LRA Table 3.4.2-1, Items 2b, 7b, and 12b, align to GALL Report III.B2-7 because there are no items in GALL section IV, V, VII, or VIII for this material and environment combination. Plant specific note 402 was applied to Item 2b to address this issue, and should have also been applied to Items 7b and 12b. In addition, Table 3.5.1, Item 3.5.1-50, does not discuss the mechanical components which refer to that item.

As described in Note E for Items 2b, 7b, and 12b (LRA Table 3.4.2-1), consistency with GALL Report III.B2-7 and Table 3.5.1-50 is maintained for the material, environment, and aging effect. However, a different aging management program is credited, the External Surfaces Monitoring Program in lieu of the Structures Monitoring Program.

The literature indicates that aluminum resists corrosion due to the presence of a thin aluminum oxide film covering the surface. Therefore, according to the EPRI Mechanical Tools (TR-1010639), an aggressive environment consisting of a wetted surface or pooled liquid, oxygen, and contaminants must be present for corrosion to occur in aluminum. The ARV local actuator filter housing exterior surfaces are subjected to an air - outdoor (exterior) environment in which the potential for atmospheric moisture exists. However, atmospheric moisture does not provide a significant source of contaminants. There is also no operating experience at VEGP which presents a case for significant loss of material for aluminum in an air - outdoor (exterior) environment. However, SNC has taken a conservative position to manage any effects of loss of material on the aluminum filter housings with the External Surfaces Monitoring Program. The External Surfaces Monitoring Program is a program especially designed to inspect external surfaces of mechanical system components in external air environments such as the aluminum alloy ARV local actuator filter housings. The Structural Monitoring Program is designed to inspect structural components, not mechanical components. Therefore, the External Surfaces Monitoring Program is the appropriate program to manage the components listed in LRA Table 3.4.2-1, Items 2b, 7b, and 12b.

The VEGP External Surfaces Monitoring Program takes exception to GALL AMP XI.M36 in that additional materials such as aluminum used for the components in question will be included within the scope of inspections. This is considered an exception since the GALL AMP is described as being applicable to steel components only.

A License Renewal Application amendment is required to add plant specific note 402 where it was omitted, and to revise Table 3.5.1, item 3.5.1-50, to discuss the mechanical components.

## AMR Audit - 3.4-05

LRA Table 3.4.2-1, Items 3a and 3b, provide VEGP's AMRs for management of loss of material and cracking in the main steam system Nickel alloy flexible connectors that are exposed to a treated water (interior) environment. For these AMR items, explain why One-Time Inspection Program and Water Chemistry are capable and sufficient to manage loss of material and cracking in these components without crediting the need for more periodic inspections of these components.

## VEGP Response:

In the LRA, VEGP identified the Water Chemistry Control Program and the One-Time Inspection Program for managing these flexible connectors. The One-Time Inspection Program was credited to confirm that water chemistry control was controlling loss of material and cracking as expected. Further consideration determined that the One-Time Inspection Program would not be effective for managing these components. To confirm the effectiveness of the Water Chemistry Control Program in mitigating aging of these flexible connectors, VEGP will credit VT-2 inspections performed in accordance with the Inservice Inspection Program instead of the One-Time Inspection Program. VEGP believes that the combination of the Water Chemistry Control Program and the Inservice Inspection Program provides a reasonable approach to management of these flexible connectors. Additional discussion is provided below:

The configuration of the flexible connectors is a nickel alloy (Alloy 625, SB-444) bellows with stainless steel braid and spring on the outside to provide strength. SNC notes that the Alloy 625 bellows material is a Nickel-Chromium-Molybdenum-Columbium alloy with composition significantly different than the Nickel-Chromium-Iron alloys that have proven to be susceptible to stress corrosion cracking in ASME Class 1 component locations. Additionally, in this application, which is a sample line from the steam generator secondary side, the flexible connectors are exposed to lower temperatures and pressures than nickel alloys in the RCS. The environment consists of treated water, not borated water, so PWSCC is not applicable.

Periodic VT-2 inspection in accordance with the ISI Program is considered to be the most appropriate inspection technique for this component. This configuration can not be inspected reliably with an external UT examination due to the presence of the support spring and braid. Visual examination of the internal surfaces is considered to be impractical since the flexible connectors are welded in place, and because of the small diameter, ½" (OD). Additionally, the bellows is a thin-walled component. Any cracks initiated in this component would be expected to extend thru-wall in a relatively short time frame. As a result, internal visual examinations would be unlikely to detect partially thru-wall cracks in the bellows. VT-2 examinations are performed every refueling outage.

In addition, because these are small lines ½" (OD), any leakage would be limited. These flexible connectors are also provided with isolation valves so that any leakage can easily be isolated. As a result, the consequence of leakage from these flexible connectors is limited to minor loss of secondary side inventory.

VEGP will revise LRA Table 3.4.2-1, items 3a and 3b, to credit the Inservice Inspection Program in lieu of the One-Time Inspection Program to verify effectiveness of water chemistry control.

A License Renewal Application Amendment is required.

## AMR Audit - 3.4-06

LRA Table 3.4.2-1, Items 4a and 4b, provide VEGP's AMRs on management of loss of material and cracking of main steam system stainless steel flow restrictors/elements that are exposed to an air - outdoor (interior, wetted) environment. For these AMR items, VEGP credits the One-Time Inspection Program to manage loss of material and cracking in the components. In addition, for Item 4h In AMR Item 4h, VEGP concludes that there are no applicable aging effects for the main steam system stainless steel flow restrictors/elements that are exposed to an air - outdoor (exterior) environment.

A. Provide your basis why the One-Time Inspection Program alone is capable, sufficient, and valid to manage loss of material and cracking in the surfaces of the stainless steel flow restrictors that are exposed to an air - outdoor (interior, wetted) environment without crediting the need for periodic inspections of these components surfaces.

B. Clarify why it is valid to conclude that there are not any applicable aging effects for the surfaces of stainless steel flow restrictors/elements that are exposed to an air - outdoor (exterior) environment when the LRA identifies that material and cracking are applicable aging effects for stainless steel flow restrictors/elements that are exposed to an air - outdoor (interior, wetted) environment.

## VEGP Response:

A. The One-Time Inspection Program is sufficient to manage loss of material and cracking in the surfaces of stainless steel flow orifice/elements in the air-outdoor (interior, wetted) environment without the need for periodic inspections. VEGP's review of materials aging research concluded that even though no significant aging effects are expected, a conservative assumption was made to consider localized corrosion of stainless steels when the condensation or wetted stressors are applied. The One-Time Inspection Program will confirm that either an aging effect is not occurring, or is occurring so slowly as to not affect the component's intended function(s) during the period of extended operation. For the internal surfaces of stainless steel components exposed to outdoor air when wetted, a one-time inspection for loss of material and/or cracking will indicate the need for follow-up inspections. If it is determined that age related degradation is progressing at a rate that will affect the component's intended function during the period of extended operation, then follow-up inspections will be performed to monitor the progression of aging, which may result in expansion of the sample size or other corrective actions deemed appropriate.

B. SNC's aging management strategy for stainless steel flow orifice/elements in the air-outdoor (exterior) and air-outdoor (interior) environments is that there are no aging effects requiring management for this material in these environments. Components in these environments are not exposed to concentration of contaminants from alternately wetted and dried conditions required for crevice corrosion and pitting. Rain tends to wash off contaminants, instead of concentrating them. Therefore, the air-outdoor (exterior) and air-outdoor (interior) environments are not considered aggressive to stainless steels. This conclusion is consistent with EPRI 1010639, Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools. EPRI 1010639 indicates that stainless steels are resistant to general corrosion, crevice corrosion, pitting, and cracking in the subject environments.

## AMR Audit - 3.4-07

LRA Table 3.4.2-1, Items 4h, 5c, 5d, 6a,and 6c, provide VEGP's AMRs on main steam system stainless steel ARV discharge path flow restrictors and ARV local actuator oil reservoirs that are exposed to air - outdoor (interior) and air - outdoor (exterior) environments. In these AMRs, VEGP concludes that there are not any applicable aging effects requiring management (AERMs). Provide your basis why it is valid to conclude that there are not any AERMs for the component surfaces that are exposed to either the air - outdoor (interior) or the air - outdoor (exterior) environments.

## VEGP Response:

SNC's aging management strategy for stainless steel piping components in the air-outdoor (exterior/interior) environment is that there are no aging effects requiring management for this material in this environment, in the absence of stressors such as wetted or condensation. This conclusion is consistent with EPRI 1010639, Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools. EPRI 1010639 indicates that stainless steels are resistant to general corrosion, crevice corrosion, pitting, and cracking in the subject environment.

Refer to the revised response to question 3.4-06 (B) for additional discussion.

## AMR Audit - 3.4-08

LRA Table 3.4.2-1, Item 7a, provides VEGP's AMR on loss of material in main steam system aluminum alloy ARV local actuator oil reservoir filler/breather cap surfaces that are exposed to an air - outdoor (interior) environment. In this AMR, VEGP credits the One-Time Inspection Program to manage loss of material in the surfaces of the caps that are exposed to an air - outdoor (interior) environment. Provide your basis (taking into account your response to Question 3.4-04) why a One-Time Inspection is valid, capable, and sufficient to manage loss of material in the surfaces of the ARV local actuator oil reservoir filler/breather caps that are exposed to an air - outdoor (interior) environment without the need to credit more periodic examinations of the interior component surfaces.

## VEGP Response:

According to the EPRI Mechanical Tools (TR-1010639), an aggressive environment consisting of a wetted surface or pooled liquid, oxygen, and contaminants must be present for corrosion to occur in aluminum. The ARV local actuator oil reservoir filler/breather cap interior surfaces are subjected to an air - outdoor (interior) environment in which the potential for atmospheric moisture exists. However, atmospheric moisture does not provide a significant source of contaminants. And, due to the sheltered nature of the interior surfaces, there would not be a continuous supply of contaminants. Furthermore, aluminum resists corrosion due to the presence of a thin aluminum oxide film covering the surface. There is also no operating experience at VEGP which presents a case for significant loss of material for aluminum in an air - outdoor (interior) environment. Therefore, SNC plans to use the One-Time Inspection Program to verify no loss of material in the aluminum ARV local actuator oil reservoir filler/breather cap surfaces that are exposed to an air - outdoor (interior) environment.

## AMR Audit - 3.4-09

LRA Table 3.4.2-2, Item 5a, provides VEGP's AMR for management of loss of material in the feedwater system carbon steel guard pipes that are exposed to an air - indoor (interior) environment. LRA claims consistency with the GALL Report V.A-19 that rolls up to Table Item 3.2.1-32. The LRA credits the One-Time Inspection Program to manage loss of material in lieu of using the VEGP Piping and Ducting Internal Inspection Program (which correlates to GALL AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program," as recommended in GALL AMR Item V.A-19). For these AMR items, please provide your basis for aligning this AMR item to an AMR in the GALL Report for steel containment spray system piping components, and why the One-Time Inspection Program is valid, sufficient, and capable of managing loss of material in these components without crediting the more periodic inspections that would be performed in accordance with the VEGP Piping and Ducting Internal Inspection Program. As part of this basis, please also clarify whether or not any exceptions taken in your One-Time Inspection Program against the recommended program elements in GALL AMP XI.M32, "One-Time Inspection," are applicable to this AMR, and if so, justify why these exceptions are acceptable to manage loss of material in carbon steel guard pipes.

## VEGP Response:

VEGP LRA Table 3.4.2-2, Item 5a, for Steam and Power Conversion System "Feedwater System" was aligned to GALL Table V.A, Item V.A-19, for Engineered Safety Features System "Containment Spray System," because there are no GALL AMR lines in either Chapter VIII, "Steam and Power Conversion System," or Chapter VII, "Auxiliary Systems," which evaluate the combination of carbon steel piping exposed to an "Air - Indoor (Interior)" environment. GALL Table V.A, Item V.A-19, is a match to VEGP LRA Table 3.4.2-2, Item 5a, for component, material, environment, and aging effect requiring management. VEGP chose to credit a different aging management program than GALL for this particular component.

Typically, loss of material is expected for carbon steel exposed to an "Air - Indoor (Interior)" environment. However, this expectation presumes a continuous source of both oxygen and moisture from atmospheric humidity to provide the necessary ingredients for corrosion to occur. The guard pipes evaluated in this line item are not open to atmosphere. They are sealed on both ends. Without a continuous source of either oxygen or moisture any corrosion will be insignificant. In addition, the pipe-to-guard pipe annulus is provided with a high pressure alarm to identify leakage into the annulus from the cooling water return piping from the Steam Generator Blowdown Heat Exchangers. This ensures that leakage into the pipe-to-guard pipe annulus will be identified and corrected promptly. Since progressive loss of material is not expected on the interior surfaces of these guard pipes, VEGP chose to credit the One-Time Inspection Program to verify that there are no aging effects, or that any aging effects are progressing so slowly as to not affect the component's intended function during the period of extended operation, and therefore do not require additional aging management. The One-Time Inspection Program will perform a UT measurement of wall thickness from the external surface of the guard pipe to identify loss of material.

The VEGP One-Time Inspection Program does not contain any exceptions to the recommended program elements in GALL AMP XI.M32, "One-Time Inspection."

## AMR Audit - 3.4-11

LRA Table 3.4.2-2, Items 2h, 3k, and 6k, provide VEGP's AMRs on feedwater system stainless steel flow restrictors, piping components, and valve bodies under exposure to an air - outdoor (exterior) environment. In these AMRs, VEGP concludes that there are not any applicable aging effects requiring management (AERMs). Provide your basis why it is valid to conclude that there are not any AERMs for the stainless steel component surfaces that are exposed to the air - outdoor (exterior) environments.

## VEGP Response:

SNC's aging management strategy for stainless steel piping components in the air-outdoor (exterior) environment is that there are no aging effects requiring management for this material in this environment, in the absence of stressors such as wetted or condensation. This conclusion is consistent with EPRI 1010639, Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools. EPRI 1010639 indicates that stainless steels are resistant to general corrosion, crevice corrosion, pitting, and cracking in the subject environment.

Refer to the revised response to question 3.4-06 (B) for additional discussion.

## AMR Audit - 3.4-12

LRA Table 3.4.2-3, Item 7a, provides VEGP's AMR for management of loss of material in carbon steel steam generator blowdown (SGBD) trim heat exchanger shell surfaces that are exposed to raw water - river water (interior) environment. The LRA claims consistency with the GALL Report VIII.F-5 that rolls up to Table Item 3.4.1-31. The LRA credits the Periodic Surveillance and Preventive Maintenance Activities to manage this aging effect in lieu of the VEGP Generic Letter 89-13 Program (which correlates to GALL AMP XI.M20, "Open-Cycle Cooling Water System," as recommended in GALL AMR Item VIII.F-5). For this AMR item, provide your basis why the Periodic Surveillance and Preventative Maintenance Activities are valid, sufficient, and capable of managing loss of material in these components in lieu of crediting the inspections that would be performed in accordance with the program elements for the VEGP Generic Letter 89-13 Program.

## VEGP Response:

NRC Generic Letter 89-13 is applicable to "the system or systems that transfer heat from safety-related structures, systems, or components to the UHS." For VEGP, Generic Letter 89-13 only applies to the Nuclear Service Cooling Water (NSCW) System. The environment in the NSCW System is "raw water - NSCW." The steam generator blowdown (SGBD) trim heat exchanger is not part of, nor is it cooled by, the NSCW System. Therefore this component is not in the scope of the VEGP Generic Letter 89-13 Program.

The SGBD trim heat exchanger is a non-safety related component which is cooled by the non-safety related Turbine Plant Cooling Water (TPCW) System. The environment in the TPCW System is "raw water - river water." Since the Generic Letter 89-13 Program is not applicable to this component, VEGP credited Periodic Surveillance and Preventive Maintenance Activities for aging management. As noted in Appendix B to the LRA, section B.3.21, a program for periodic inspection of the SGBD trim heat exchanger on each unit already exists. These components are visually inspected in accordance with procedure 83321-C for fouling, corrosion, coating failure, and structural/mechanical damage. These inspections are similar to inspections that would be performed under the Generic Letter 89-13 Program. VEGP operating experience with these inspections indicates that they are sufficient and capable to manage loss of material of the SGBD trim heat exchangers.

## AMR Audit - 3.4-13

LRA Table 3.4.2-3, Items 3b, 8i, 12a, and 13i, provide VEGP's AMRs for management of loss of material in stainless steel steam generator blowdown processing system flow orifices/elements, piping components, strainer housings, and valve bodies under exposure to an treated water (interior, aggressive chemistry) environment. In these AMRs, VEGP credits the One-Time Inspection Program to manage loss of material in the component surfaces that are exposed to this environment. Provide your basis why the One-Time Inspection Program is considered to be valid, sufficient, and capable of managing loss of material in these components in lieu of crediting the more periodic inspections of the interior component surfaces. As part of this basis, clarify: (1) how a one-time inspection can provide for adequate management if the water chemistry is considered to be aggressive and capable of inducing corrosion in the components, and (2) whether or not any exceptions taken in your One-Time Inspection Program against the recommended program elements in GALL AMP XI.M32, "One-Time Inspection," are applicable to this AMR, and if so, justify why these exceptions are acceptable to manage loss of material in the interior surfaces of these carbon steel components.

## VEGP Response:

The "(Aggressive Chemistry)" environment stressor is applied to LRA Table 3.4.2-3, Items 3b, 8i, 12a, and 13i to address existing stainless steel components, and potential replacement components, in the Steam Generator Blowdown System downstream of the demineralizers.

As noted in plant-specific note 405, which is applied to the above line items, stainless steel piping components are expected to be resistant to chemical attack. However, to provide assurance that no loss of material is occurring, or is occurring slowly enough to not affect the components' intended functions during the period of extended operation, the One-Time Inspection Program is credited for managing loss of material in the stainless steel components as a conservative measure.

The VEGP One-Time Inspection Program does not contain any exceptions to the recommended program elements in GALL AMP XI.M32, "One-Time Inspection."

## AMR Audit - 3.4-14

LRA Table 3.4.2-3, Items 8c and 13c, provide VEGP's AMRs for management of loss of material in carbon steel steam generator blowdown processing system piping components and valve bodies under exposure to a treated water (interior, aggressive chemistry) environment. In these AMRs, VEGP credits the Flow-Accelerated Corrosion Program to manage loss of material in the component surfaces that are exposed to this environment. For these components, clarify which aging mechanisms can induce loss of material in the surfaces that are exposed to the treated water (interior, aggressive chemistry) environment.

## VEGP Response:

The affected piping has not been subjected to metallurgical analysis, so the specific aging mechanism(s) which are active in this material and environment combination have not been confirmed. However, the loss of material is easily identifiable via ultrasonic testing, and is therefore considered to be a form of general corrosion, as opposed to localized corrosion such as pitting.

These components will be scheduled for UT inspection by the Flow-Accelerated Corrosion Program. Corrosion of these components is not modeled by CHECWORKS™, therefore scheduling will be performed in accordance with the guidance in the Flow-Accelerated Corrosion Program for "susceptible but not modeled" lines.

## AMR Audit - 3.4-15

LRA Table 3.4.2-4, Item 15b, provides VEGP's AMR for management of loss of material in carbon steel CST degasifier tanks that are exposed to an air outdoor (exterior) environment. The LRA claims consistency with the GALL Report VIII.G-40 that rolls up to Table Item 3.4.1-20. The LRA credits the External Surfaces Monitoring Program to manage this aging effect in lieu of Aboveground Steel Tanks Program (GALL AMP XI.M29) as recommended in GALL Report. Discuss how the program elements for the External Surfaces Monitoring Program compare to the NRC's recommended program elements in GALL AMP XI.M29 and identify any differences and justify the use of the External Surfaces Monitoring Program to manage the loss of material aging effect.

## VEGP Response:

GALL AMP XI.M29, Aboveground Steel Tanks, uses a combination of coating of the external surfaces of a tank, sealing of the tank to foundation interface, external visual inspections of accessible portions of a tank and of the tank to foundation interface, and thickness measurements to identify any external corrosion of the inaccessible portions of a tank bottom.

VEGP has taken the conservative position of not crediting coatings for aging management. However, VEGP agrees that observation of the condition of the paint or coating is an effective method for identifying degradation of the underlying material. Therefore, monitoring of the condition of coatings will be included in the inspection criteria of the External Surfaces Monitoring Program along with the inspection criteria to monitor for degradation of the component materials. Refer to the response to question B.3.8-02 for additional discussion.

The CST degasifier tank addressed in LRA Table 3.4.2-4, Item 15b, is a vertical cylindrical tank supported by a skirt. This tank is insulated. There is no tank to foundation interface. The bottom of the tank is accessible for visual inspection, so the GALL program elements related to sealing of the tank to foundation interface, external visual inspections of the tank to foundation interface, and thickness measurements of the tank bottom to identify external degradation are not applicable to this tank.

The remaining elements of the GALL Aboveground Steel Tanks program consist of external visual inspections of the accessible portions of the tank. These elements are included in the VEGP External Surfaces Monitoring Program, therefore VEGP believes that this program will adequately manage loss of material from the CST degasifier tank during the period of extended operation.

## AMR Audit - 3.4-16

LRA Table 3.4.2-4,Items 9i, 9o,14a, and 14b, provide VEGP's AMR for management of loss of material in stainless steel auxiliary feedwater system piping components and TDAFWP steam exhaust condensate spargers that are exposed to either drainage - dirty (interior) or drainage - dirty (exterior) environment. VEGP credits the Piping and Duct Internal Inspection Program to manage loss of material in these components. Clarify which aging mechanisms have the potential to result in loss of material in these components. In addition, clarify whether the drainage - dirty (interior) and drainage -dirty (exterior) environments are considered to be aggressive enough to induce accelerated corrosion of these components, in spite of the normal general corrosion resistance that is imparted by the Chromium alloying levels in the stainless steel materials. Consistent with your clarifications, provide your basis why the program elements of the Piping and Duct Internal Inspection Program are sufficient to manage loss of material induced by the relevant aging mechanisms, especially if these environments have the potential to result in accelerated corrosion of the stainless steel components.

## VEGP Response:

VEGP defines Drainage - Dirty as an environment used to describe dirty leakage or leak-off from equipment containing unmonitored liquids. Dirty drainage may contain treated water, borated water, raw waters, or oils. Contaminants are assumed to be present.

The components listed in LRA Table 3.4.2-4, items 9i, 9o,14a, and 14b are located in the Auxiliary Feedwater (AFW) Pumphouses.

The following table lists the plant systems located in the AFW Pumphouses, and the primary fluids contained in those systems. The expected internal environments listed in the table constitute the major sources of possible leakage or drainage into the building sumps where the piping and spargers in question are located.

| VEGP System | VEGP System Name | Expected Internal Environment |
|---|---|---|
| 1215 | Auxiliary Bldg Drain Sys - Nonrad | Drainage - Dirty (see below; may also contain rainwater collected in the sumps) |
| 1301 | Main Steam System | Steam, Treated Water |
| 1302 | Auxiliary Feedwater System | Treated Water, Lube Oil |
| 1305 | Condensate and Feedwater System | Treated Water |
| 1322 | Auxiliary Steam System | Steam, Treated Water |
| 1411 | Condensate Chemical Injection System | Treated Water |
| 1418 | Demineralized Water System | Treated Water |
| 2301 | Fire Protection System | Raw Water - Well Water |
| 2401 | Instrument Air, Service Air, Breathing Air System | Air. Not a possible source of leakage. |
| 2419 | Utility Water System | Raw Water - Well Water |
| 2420 | Instrument Air System | Air. Not a possible source of leakage. |

As can be seen from the table, these are environments where stainless steels are routinely employed due to its inherent corrosion resistance. None of these environments are aggressive enough to induce accelerated corrosion of stainless steels, therefore it is expected that no mixture of these environments in the building sumps will be aggressive enough to induce accelerated corrosion of the stainless steel piping and spargers which are exposed to the fluid collected in the building sumps.

The aging mechanisms which have the potential to result in loss of material from stainless steels in the Drainage - Dirty environment are the same as for a raw water environment, i.e.: pitting, crevice corrosion, and MIC.

For stainless steels exposed to the Drainage - Dirty environment, VEGP credits the Piping and Duct Internal Inspection Program for managing loss of material due to the uncertainties inherent in the quality of water drained into a sump. Some of the possible sources are raw water sources, and the potential exists for contamination from unknown sources. However, since the majority of the potential sources of leakage or drainage are from systems where the chemistry is controlled, and because none of the known potential sources are aggressive with respect to stainless steels, a program of periodic inspections such as the Piping and Duct Internal Inspection Program is adequate to manage loss of material from stainless steels in the Drainage - Dirty environment during the period of extended operation.

## AMR Audit - 3.4-17

LRA Table 3.4.2-4, Items 3a, 9h, 9m, 12b, 17a, and 19j, provide VEGP plant-specific AMRs for various stainless steel component/commodity groups (including specific piping components, pump casings, valve bodies , flow orifices/elements and liners) under exposure either an air - outdoor (interior) or air - outdoor (exterior) environment. In these AMRs, VEGP states that there are not any applicable aging effects requiring management (AERMs). Provide your basis why it is valid to conclude that there are not any AERMs for the stainless steel component surfaces that are exposed to the air - outdoor (interior) or air - outdoor (exterior) environments.

## VEGP Response:

SNC's aging management strategy for stainless steel piping components, pump casings, valve bodies, flow orifices/elements, and tank liners in the air-outdoor (exterior/interior) environment is that there are no aging effects requiring management for this material in this environment, in the absence of stressors such as wetted or condensation. This conclusion is consistent with EPRI 1010639, Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools. EPRI 1010639 indicates that stainless steels are resistant to general corrosion, crevice corrosion, pitting, and cracking in the subject environment.

Refer to the revised response to question 3.4-06 (B) for additional discussion.

## AMR Audit - 3.4-18

LRA Table 3.4.2-4, Items 16a and 16b, provide VEGP plant-specific AMRs for condensate storage tank (CST) elastomeric diaphragms under exposure to either a treated water (interior) environment or an air - outdoor (exterior) environment. In these AMRs, VEGP identifies that changes in material properties is an applicable aging effect requiring management (AERM) for these diaphragms and credits the Periodic Surveillance and Preventative Maintenance Activities for management of this aging effect. Material properties are not extensive thermodynamic properties and thus are not capable of being monitored and sized for by inspection techniques. Thus, any changes in material properties must either be managed either by: (1) direct destructive testing and analysis, or (2) performing appropriate material property analyses and linking appropriate inspection techniques for the detection extensive aging effects (such as cracking or loss of material) prior to a loss of component function, taking in account the limiting material property for the component material. Provide the following information with respect to these AMRs:

A. Identify the material properties that may be impacted by exposure of these elastomeric diaphragms to the treated water (interior) environment and an air - outdoor (exterior) environments.

B. Clarify whether appropriate material property analyses have been performed to date that evaluate how the impacted material properties for these diaphragms will change through the expiration of the period of extended operation, and if so, summarize the results of these analyses.

C. Provide your basis why the inspections credited under the Periodic Surveillance and Preventative Maintenance Activities are considered to be capable of detecting applicable detectable extensive thermodynamic property aging effects (e.g., loss of material and cracking) in the diaphragms prior to a component loss of intended function, after taking in account the limiting material properties through the expiration of the period of extended operation.

## VEGP Response:

A. The material properties that may be impacted by exposure of elastomer diaphragms to the treated water (interior) and air - outdoor (exterior) environments include a high degree of flexibility, good resiliency (low modulus of elasticity), and chemical and abrasion resistance. Aging of these components may lead to progressive hardening, loss of resiliency, cracking or loss of material.

B. No material property analysis per se has been performed by VEGP on the CST diaphragms. However, industry guidance, specifically EPRI report 1007933, "Aging Assessment Field Guide," provides guidance for performing visual and tactile inspections of elastomers. These inspection techniques are proven effective in identifying changes in the material properties of elastomers, and are in use throughout the industry. Inspections of elastomers under Periodic Surveillance and Preventive Maintenance Activities will be performed in accordance with this industry guidance and manufacturer recommendations. This includes flexing of the material to identify cracking or crazing, and examining for waxy or chalky residue, peeling, blistering, delamination, flaking, discoloration, physical distortion, embrittlement (hardening), or gross softening.

C. NRC Staff has accepted use of the inspection techniques described by above in several license renewal SERs, including Palisades Nuclear Plant (NUREG-1871, section 3.0.3.3.1), Monticello

Nuclear Generating Plant (NUREG-1865, section 3.0.3.3.2), and Farley Nuclear Plant (NUREG-1825, section 3.0.3.3.4). The Palisades SER also notes that the DC Cook and Millstone applications applied similar inspection techniques for elastomers.

## AMR Audit - 3.4-19

LRA Table 3.4.2-5, Item 3a and 5a, provide VEGP's AMRs on auxiliary steam system carbon steel piping components and valve bodies under exposure to an air - indoor (interior) environment. The LRA claims consistency with the GALL Report V.A-19 that rolls up to Table Item 3.2.1-32. In these AMRs, VEGP concludes that loss of material is an applicable AERM and credits the One-Time Inspection Program to manage this aging effect in lieu of the VEGP Piping and Duct Internal Inspection Program, which is the corresponding AMP (GALL AMP XI.M38) that is recommended for GALL Report for Item V.A-19. For these AMR items, provide your basis for aligning these AMR item to an AMR in the GALL Report for steel containment spray system piping components, and why the One-Time Inspection Program is valid, sufficient, and capable of managing loss of material in these components without crediting the more periodic inspections that are performed in accordance with the program elements for the VEGP Piping and Ducting Internal Inspection Program. As part of this basis, clarify whether or not any exceptions taken in your One-Time Inspection Program against the recommended program elements in GALL AMP XI.M32, "One-Time Inspection," are applicable to this AMR, and if so, justify why these exceptions are acceptable to manage loss of material in carbon steel piping and valve body components.

## VEGP Response:

VEGP LRA Table 3.4.2-5, items 3a and 5a, for Steam and Power Conversion System "Auxiliary Steam System" were aligned to GALL Table V.A, Item V.A-19, for Engineered Safety Features System "Containment Spray System," because there are no GALL AMR lines in either Chapter VIII, "Steam and Power Conversion System," or Chapter VII, "Auxiliary Systems," which evaluate the combination of carbon steel piping exposed to an "Air - Indoor (Interior)" environment. GALL Table V.A, Item V.A-19, is a match to VEGP LRA Table 3.4.2-5, items 3a and 5a, for component, material, environment, and aging effect requiring management. VEGP chose to credit a different aging management program than GALL for these components.

For carbon steel piping components and valve bodies exposed to an Air - Indoor (Internal) environment where condensation or wetting are not present, some loss of material due to general corrosion is expected. However, VEGP expects the degree of corrosion for this material and environment combination to be minor and to progress slowly. VEGP believes that a one-time inspection will confirm this expectation, and that additional inspections will not be warranted. If the one-time inspection indicates that corrosion of this material and environment combination has progressed such that the intended function of a component could be affected during the period of extended operation, then the impacted components will be included in the Piping and Duct Internal Inspection Program, or other program as appropriate. Carbon steel components exposed to condensation, wetting, or Air - Outdoor (Internal) are managed by the Piping and Duct Internal Inspection Program because the potential for exposure to water negates the expectation that corrosion would progress slowly.

The VEGP One-Time Inspection Program does not contain any exceptions to the recommended program elements in GALL AMP XI.M32, "One-Time Inspection."

## AMR Audit - 3.4-20

LRA Table 3.4.2-5, Item 2c, provides VEGP's AMR on auxiliary steam system stainless steel flow orifices/elements that are exposed to an air - outdoor (exterior) environment. In this AMR, VEGP concludes that there are not any applicable aging effects requiring management (AERMs). Provide your basis why it is valid to conclude that there are not any AERMs for the flow orifice/element component surfaces that are exposed to either the air - outdoor (exterior) environment.

## VEGP Response:

SNC's aging management strategy for stainless steel flow orifices/elements in the air-outdoor (exterior) environment is that there are no aging effects requiring management for this material in this environment, in the absence of stressors such as wetted or condensation. This conclusion is consistent with EPRI 1010639, Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools. EPRI 1010639 indicates that stainless steels are resistant to general corrosion, crevice corrosion, pitting, and cracking in the subject environment.

Refer to the revised response to question 3.4-06 (B) for additional discussion.

## AMR Audit - 3.4-21

Item Number 3.4-09 of LRA Table 3.4.1, "Summary of Aging Management Evaluations for Steam and Power Conversion Systems in Chapter VIII of NUREG-1801", states that reduction of heat transfer due to fouling is an applicable aging effect required management (AERM) for copper and stainless steel heat exchanger tubes that are exposed to treated water.
In this AMR, VEGP credits the water chemistry management program and one time inspection for aging management.
Please clarify why one time inspection programs considered to be capable of managing reduction of heat transfer due to fouling, in lieu of performing periodic inspection of these heat exchanger tubes.

## VEGP Response:

Treated water is defined as demineralized water, potentially with additional treatments such as corrosion inhibitors, biocides, or de-aeration. Closed cooling water is specifically excluded from this environment.

Fouling is normally associated with macro organisms (such as barnacles, mussels, clams, algae, and others) or with significant amounts of silt. These can all be present in raw water, but are not expected in treated water due to the pure nature of the water, the lack of oxygen and contaminants to support macro organisms, and the application of biocides as dictated by sample results (where applicable).

Corrosion product build-up may also contribute to fouling. In treated water applications where chemistry controls are not maintained, corrosion product particulates could accumulate in low flow areas of heat exchangers. Corrosion product particulates are not expected to be generated in significant quantities in treated water applications where dissolved oxygen and other contaminants are maintained within limits that have been demonstrated to be effective in controlling corrosion.

Therefore, significant fouling is not expected in treated water applications where proper chemistry controls are maintained.

The review of VEGP operating experience did not identify any instances of fouling of heat exchanger components exposed to a treated water environment.

The Water Chemistry Control Program ensures that proper chemistry controls are maintained. The One-Time Inspection Program is credited to verify the effectiveness of the Water Chemistry Control Program. This position is consistent with the aging management programs discussed in NUREG-1801, Volume 1, Table 4, Item 9, and the associated NUREG-1801, Volume 2 items.

## AMR Audit - 3.4-22

Provide your basis why the LRA does not include AMR line items in the Steam and Power Conversion Systems that correspond to the following AMRs in Section VIII of the GALL Report, Revision 1, Volume 2:

A. Type 2 AMRs in LRA Table 3.4.2-1 for the main steam system corresponding to AMRs VIII.B1-1, VIII.B1-7, and VIII.B1-10 in Table VIII.B1 of the GALL Report, Volume 2, "STEAM AND POWER CONVERSION SYSTEM, Main Steam System (PWR)."

B. Type 2 AMRs in LRA Table 3.4.2-2 for the feedwater system corresponding to AMRs VIII.D1-1, VIII.D1-2, VIII.D1-3, VIII.D1-6, and VIII.D1-7 in Table VIII.D1 of the GALL Report, Volume 2, "STEAM AND POWER CONVERSION SYSTEM, Feedwater System (PWR)."

C. Type 2 AMRs in LRA Table 3.4.2-3 for the steam generator blowdown system corresponding to AMRs VIII.F-1, VIII.F-2, VIII.F-3, VIII.F-4, VIII.F-6, VIII.F-7, VIII.F-8, VIII.F-9, VIII.F-10, VIII.F-11, VIII.F-12, VIII.F-13, VIII.F-14, VIII.F-15, VIII.F-16, VIII.F-17, VIII.F-18, VIII.F-19, VIII.F-20, VIII.F21, VIII.F-22, VIII.F-24, and VIII.F-27 in Table VIII.F of the GALL Report, Volume 2, "STEAM AND POWER CONVERSION SYSTEM, Steam Generator Blowdown System."

D. Type 2 AMRs in LRA Table 3.4.2-4 for the auxiliary feedwater system corresponding to AMRs VIII.G-1, VIII.G-2, VIII.F-4, VIII.G-5, VIII.G-6, VIII.G-7, VIII.G-8, VIII.G-9, VIII.G-10, VIII.G-11, VIII.G-13, VIII.G-14, VIII.G-15, VIII.G-16, VIII.G-17, VIII.G-18, VIII.G-19, VIII.G-20, VIII.G21, VIII.G-22, VIII.G-23, VIII.G-24, VIII.G-25, VIII.G-26, VIII.G-27, VIII.G-28 VIII.G-30, VIII.G-31, VIII.G-33, VIII.G-34, VIII.G-36, and VIII.G-37 in Table VIII.G of the GALL Report, Volume 2, "STEAM AND POWER CONVERSION SYSTEM, Auxiliary Feedwater System."

## VEGP Response:

The VEGP LRA does not include AMR line items in the Steam and Power Conversion Systems that correspond to the GALL AMR line items listed in this question for the following reasons:

1) Component not in scope:
GALL Items VIII.F-6, VIII.F-7, VIII.F-8, VIII.F-9, VIII.F-10, and VIII.F-11.

2) The VEGP AMR process did not identify the listed material for the component:
GALL Items VIII.D1-1, VIII.D1-2, VIII.F-1, VIII.F-2, VIII.F-3, VIII.F-12, VIII.F-13, VIII.F-14, VIII.F-15, VIII.F-16, VIII.F-17, VIII.F-18, VIII.F-19, VIII.F-27, VIII.G-6, VIII.G-7, VIII.G-8, VIII.G-9, VIII.G-10, VIII.G-14, VIII.G-15, VIII.G-16, VIII.G-17, VIII.G-18, VIII.G-19, VIII.G-20, VIII.G21, VIII.G-22, VIII.G-23, VIII.G-24, VIII.G-25, and VIII.G-26.

3) The VEGP AMR process did not identify the listed environment for the component and material combination:
GALL Items VIII.B1-1, VIII.B1-7, VIII.D1-3, VIII.D1-6, VIII.F-4, VIII.F-20, VIII.F21, VIII.F-22, VIII.F-24, VIII.G-1, VIII.G-2, VIII.G-4, VIII.G-5, VIII.G-11, VIII.G-13, VIII.G-27, VIII.G-28, VIII.G-30, VIII.G-31, VIII.G-33, VIII.G-34, and VIII.G-36.

4) The Aging Effect/Mechanism listed is "Cumulative fatigue damage/ fatigue."
GALL Items VIII.B1-10, VIII.D1-7, and VIII.G-37.
There are no Steam & Power Conversion System components where cracking -CFD is an aging effect requiring management, therefore there are no line items in LRA Tables 3.4.2-1, 3.4.2-2, or

3.4.2-4 that correspond to the related GALL AMR line items. See the response to question 3.0-01 for a more complete explanation of why there are no items in Tables 3.4.2-1, 3.4.2-2, or 3.4.2-4 that align to GALL AMR line items VIII.B1-10, VIII.D1-7, and VIII.G-37.

## AMR Audit - 3.5-01

LRA Table 3.5.2-1 identifies Inservice Inspection Program- IWL as the aging management program for managing the aging effect for Item 3.5.1-1. However, the discussion column in Table 3.5.1 refers to the plant-specific ISI-IWE as the aging management program for managing the aging effect for Item 3.5.1-1. Clarify the discrepancies between these Tables.

## VEGP Response:

This is an inadvertent error. The discussion column in Table 3.5.1 Item 3.5.1-1 should be changed to read "...Inservice Inspection Program - IWL (Appendix B.3.31)."

A License Renewal Application amendment is required.

## AMR Audit - 3.5-02

LRA Table 3.5.1, Item 3.5.1-1, refers to LRA Subsection 3.5.2.2.1.1 in the discussion column. In Subsection 3.5.2.2.1.1, the following statement is made: "As a result, corrosion of embedded steel is managed by the Inservice Inspection Program - IWL and Structural Monitoring Program (SMP)." However, in the discussion column, the following statement is made: "VEGP manages accessible and inaccessible concrete components due to corrosion of embedded steel with the Inservice Inspection Program - IWE (Appendix B.3.30)." Provide SMP program to the related line items on Table 3.5.2-1.

## VEGP Response:

Subsection 3.5.2.2.1.1 addresses the Structural Monitoring Program (SMP) because:

- the Structures Monitoring Program is used to ensure that groundwater is monitored,
- the Structures Monitoring Program is used for examination of exposed portions of below grade concrete in the groundwater environment when uncovered during removal of backfill.

ID# 2 and 3 of Table 3.5.2-1 will be revised to incorporate Structural Monitoring Program (SMP) for 'soil' environment and 'Cracking and loss of material' aging effect

A license renewal application amendment is required.

## AMR Audit - 3.5-03

LRA Table 3.5.1, Item 3.5.1-15, refers to LRA Subsection 3.5.2.2.1.10 in the discussion column. In Subsection 3.5.2.2.1.10, the applicant states that VEGP manages loss of material due to leaching of calcium hydroxide with the Inservice Inspection Program - IWL, and the Structural Monitoring Program. However, in the discussion column, the applicant states that VEGP manages loss of material due to leaching of calcium hydroxide with the Inservice Inspection Program - IWL. If the program is only IWL, then adjust the response in the discussion column.

## VEGP Response:

Program is only IWL for accessible containment concrete. VEGP Containment concrete was constructed using ACI 211.1, which provides guidance for producing high density, low permeability concrete mix designs similar to ACI 201.2R. Further evaluation in accordance with NUREG-1801 is not required.

Last sentence in discussion column of Item number 3.5.1-15 'See Section 3.5.2.2.1.10 for further discussion." will be deleted

A license renewal application amendment is required.

## AMR Audit - 3.5-04

LRA Table 3.5.1, Item 3.5.1-31, refers to LRA Subsection 3.5.2.2.2.2(4) in the discussion column. In Subsection 3.5.2.2.2.2(4), the applicant states that the inspections are performed in accordance with Inservice Inspection Program - IWL and the Structural Monitoring Program and are conservatively credited to detect any visible corrosion. However, in the discussion column, the applicant states that the VEGP Structural Monitoring Program (Appendix B.3.32) will manage degradation of accessible and inaccessible concrete components due to corrosion of embedded steel. Explain whether the ISI-IWL is credited to manage concrete components associated with Item 3.5.1-31 due to corrosion of embedded steel. If yes, please clarify the inconsistencies in the LRA.

## VEGP Response:

Item 3.5.1-31 is applicable to below grade concrete elements for non-containment structures. So, the Inservice Inspection Program - IWL is not credited to manage concrete components associated with Item 3.5.1-31 due to corrosion of embedded steel.

LRA Subsection 3.5.2.2.2.2(4) will be modified to delete reference to IWL Program. The last sentence of section 3.5.2.2.2.2(4) will read as "However, inspections performed in accordance with the Structures Monitoring Program are conservatively credited to detect any visible corrosion."

To make it consistent, LRA Subsection 3.5.2.2.2.2(1) will be modified to read as
"(1) Loss of material due to freeze-thaw

NUREG-1800 item 3.5.2.2.2.2 (1) relates to loss of material and cracking due to freeze-thaw in below-grade inaccessible concrete areas of Groups 1-3, 5, and 7-9 structures. Further evaluation of this aging effect is recommended only for structure / aging effect combinations that are not within the structures monitoring program.

The VEGP AMR results conclude that freeze-thaw is not significant at VEGP. The basis for this conclusion in structures other than containment is the same as the basis for the Containment Building. See Section 3.5.2.2.1.9, which provides discussion related to freeze-thaw effects for all VEGP concrete structures within the scope of license renewal."

A License Renewal Application amendment is required.

## AMR Audit - 3.5-05

In LRA Table 3.5.2-1, ID 2, for soil environment, cracking and loss of material aging effect, GALL Item II.A1-7 is referred. Also, in LRA Table 3.5.2-1, ID 3, for soil environment, cracking and loss of material aging effect, GALL Item II.A1-7 is referred. The staff notes that GALL Item II.A1-7 is associated with an air-indoor uncontrolled or air-outdoor environment. Explain why GALL Item II.A1-7 is referred in LRA Table 3.5.2-1, ID 2 and ID 3 for a soil environment and the impact on aging effect/aging management.

## VEGP Response:

It is noted that GALL Item II.A1-7 does indeed include only Air-indoor uncontrolled or air-outdoor as the referenced environment. However, portions of the containment wall, buttresses and basemat concrete, foundation and subfoundation, which are located below grade, and may also be exposed to the soil environment. For completeness, the soil environment was conservatively included in the Aging Management Review (AMR) and the aging effect of change in material properties (due to leaching) and cracking and loss of material (due to corrosion of embedded steel) were identified in the LRA Table Summary in ID 2 and ID 3.

## AMR Audit - 3.5-06

In LRA Table 3.5.2-6, ID 6, for NSCW cooling tower basin component in soil environment, GALL Item III.A3-9 is referenced. The staff notes that GALL Item III.A3-9 is associated with air-indoor uncontrolled or air-outdoor environment, while GALL Item III.A3-4 is associated with a ground water/soil environment. Clarify why GALL Item III.A3-4 is not used here. If GALL Item III.A3-4 is more suitable, explain whether the SMP is also needed to manage inaccessible concrete components.

## VEGP Response:

This is an inadvertent error. GALL Item III.A3-4 should be listed for ID 6 instead of Gall Item III.A3-9, and the corresponding Table 1 Item should be 3.5.1-31. The Structural Monitoring Program is the appropriate aging management program for accessible or inaccessible concrete components.

A License Renewal Application amendment is required.

## AMR Audit - 3.5-07

In LRA Table 3.5.2-12, ID 13 for steel material, Note F and GALL Item III.A3-12 are referenced. Note F states: "Material not in NUREG-1801 for this component". However, Steel material is associated with GALL Item III.A3-12. Explain the discrepancy between GALL Item III.A3-12 and Note F associated with LRA Table 3.5.2-12, ID 13.

## VEGP Response:

This is an inadvertent error. Note C should be associated with LRA Table 3.5.2-12, ID 13 instead of Note F.

A License Renewal Application amendment is required.

## AMR Audit - 3.5-08

In LRA Table 3.5.2-7, ID 1, for air-outdoor environment, change in material properties aging effect, GALL Item III.A7-6 is referenced. The staff notes that GALL Item III.A7-6 is associated with a water-flowing environment. Explain why GALL Item III.A7-6 is referred in LRA Table 3.5.2-7 ID 1 for an air-outdoor envrionment, how Note A is referenced if the envrionment is different, and the impact on aging effect/aging management

## VEGP Response:

For LRA Table 3.5.2-7; ID 1 will be revised to add 'Water Standing' environment for second line 'Change in Material Properties' aging effect.

Though environment terminology differs from GALL the note 'A' is the best possible match for this line item.

A license renewal application amendment is required.

## AMR Audit - 3.5-09

In LRA Table 3.5.2-7, ID 2, for concrete foundations component, raw water environment, change in material properties aging effect, GALL Item III.A7-6, Note C is referenced. Note C states: "Component is different, but consistent with NUREG-1801 item for material, envrionment, and aging effect. AMP is consistent with NUREG-1801 AMP." However, GALL Item III.A7-6 does include concrete foundations component. Explain why Note C is associated with LRA Table 3.5.2-7, ID 2.

## VEGP Response:

For LRA Table 3.5.2-7; ID 2 will be revised to replace note 'C' with note 'A' for line item with 'Raw Water' environment'.

A license renewal application amendment is required.

## AMR Audit - 3.5-10

For LRA Table 3.5.2-12; page 3.5-92; material-Aluminum; environment-Air out door; item III.B2-7 (3.5.1-50); GALL Report recommends Structure Monitoring Program to manage the loss of material aging effect. Please, explain why VEGP identifies no AERM for this line item.

**VEGP Response:**

- For LRA Table 3.5.2-12; ID 10 will be revised to identify aging effect of 'Loss of Material' and aging management program 'Structural Monitoring Program' for air-outdoor environment, also replace note 'I' with 'C'.
- Table 3.5.1 Item Number 50 Discussion column will be revised to say 'Consistent with NUREG 1801'.

A license renewal application amendment is required.

## TLAA Audit - 4.1-01

Clarify whether the vendor for the VEGP polar cranes has performed a fatigue analysis for the cranes that is based on the vendor recommendation for allowable number of maximum load lifts. If so, provide your basis on whether or not the fatigue analysis for the polar cranes is a time-limited aging analysis for the VEGP LRA. If such an analysis exists, provide your response in terms of whether the vendor's fatigue analysis meets the six criteria for TLAAs in 10 CFR 54.3.

## VEGP Response:

Vendor for the VEGP polar cranes has not performed a fatigue analysis for the polar cranes.

An evaluation has been performed and that demonstrates the actual load cycles for these cranes through the period of extended operation are well below the design limits. A conservative assumption of 100 heavy lifts or less with the polar crane is substantially below the 20,000 lifts considered for a class A1 crane in CMAA 70. However, the polar crane evaluation is based only on assumed loads and does not evaluate a time-dependent aging effect.

Therefore, it is concluded that the cranes do not meet the criteria for TLAA in accordance with 10CFR 54.3.

## TLAA Audit - 4.3-01

Table 4.3.1-1 includes a column that states "counted". For all the "yes" items, please clarify whether counting is done manually or by FatiguePro. If so, please provide the periodicity.

## VEGP Response:

The following table shows the design transients from Table 4.3.1-1 in the VEGP LRA that are counted by FatiguePro with indication of whether the cycle is counted automatically or manually. Please note that manually counted cycles are also tracked using FatiguePro but are manually entered into the program rather than automatically entered directly from instrument readings. From plant procedure 83101-C, Rev. 11.1, "Review of the Fatigue and Cycle Counting Analysis results performed by FatiguePro should be performed monthly at a minimum looking for trends, limits and projections of failures." Projected cycles and projected CUFs are updated every 18 months and a report is submitted for management review. That report includes the following:

- A listing of monitored plant transients, up to date count of cycles, allowable number of cycles, and projected number of cycles for plant life.
- The actual accumulated to date and projected end of plant life CUF for all monitored locations.
- A summary of the actions taken or recommended to respond to excessive cycle or fatigue accumulation.

***Summary of RCS Design Transients Counted***

| **Operating Conditions** | **Counting Method** |
|---|---|
| RCP startup and shutdown | Automatically Counted |
| Heatup and cooldown at 100°F/h (pressurizer cooldown at 200°F/h) | Automatically Counted |
| Unit loading and unloading between 0 and 15 percent of full power | Automatically Counted |
| Refueling | Manually Counted |
| Primary side leakage test | Manually Counted |
| Loss of load without immediate reactor trip | Automatically Counted |
| Loss of power | Automatically Counted |
| Partial loss of flow | Automatically Counted |
| Reactor trip from full power With no inadvertent cooldown<br>With cooldown and no SI With cooldown and SI | Automatically Counted<br>Automatically Counted<br>Automatically Counted |
| Inadvertent SI actuation | Automatically Counted |
| **Test Conditions** | |
| Secondary side hydrostatic test | Manually Counted |

## TLAA Audit - 4.3-02

Table 4.3.1-2 provides a list of transients tracked by Fatigue Monitoring Software.

a. Please state the start of cycle counting date(s) for these transients.

b. Please describe the method used to project the 60-year cycle count for each transient.

c. Please describe how the CUFs (for these components: normal charging nozzle, alternate charging nozzle, main feedwater nozzle, and auxiliary feedwater nozzle) accumulated from the beginning of plant operation to pre-installation of FatiguePro were accounted in the counted as of 10/9/05 values.

d. UFSAR Section 3.9.1.1.1.14 (Primary Side Leakage Test) states that "A leakage test of performed after each opening of the primary system." and, "In actual practice, the primary system is pressurized, in accordance with ASME Section XI IWA-5211(a) and IWB-5221(a), as measured at the pressurizer, to prevent the pressurizer safety valves from lifting during the leakage test". The system leakage test is performed at each refueling outage in accordance with ASME Section XI. But, the table 4.3.1-2 in the LRA shows the number of U1/U2 transients 4/2.

Please provide the basis for the number of transients (primary side leakage test) of 10/9/05.

e. Table 4.3.1-2 provides a list of transients tracked by Fatigue Monitoring Software. Please confirm that the inadvertent safety injection transient (with zero projected cycles) is not used in any baseline fatigue analysis.

## VEGP Response:

a. FatiguePro data has generally been generated since June 30, 1995. When FatiguePro was first implemented in 1995, Westinghouse reviewed available plant records and established the baseline count at that time for each cycle to be counted. That effort collected data from hot function (7/86 - Unit 1 and 9/88 - Unit 2) through 9/29/95. Westinghouse Report SE-ICAT(96)-212, "Transient and Fatigue Cycle Monitoring Program Transient History Evaluation Report of Southern Nuclear Company and Georgia Power Company Vogtle Units 1 and 2" is available for your review during the audit and provides more details. The table below shows the events from Table 4.3.1-2 in the VEGP LRA that have occurred at least once and the date of the earliest known occurrence of that event on each unit.

***Earliest Date of Transients Tracked By Fatigue Monitoring Software***

| Transient | Date of First Recorded Unit 1 Event | Date of First Recorded Unit 2 Event |
|---|---|---|
| RCS heatup | 7/20/86 | 9/23/88 |
| RCS cooldown | 7/20/86 | 10/19/88 |
| Pressurizer heatup | 7/6/86 | 9/23/88 |
| Pressurizer cooldown | 7/20/86 | 10/19/88 |
| RCS leak tests | 10/31/87 | 4/29/92 |
| RCP-1 startup/shutdown | 3/14/86 | 8/22/88 |
| RCP-2 startup/shutdown | 3/14/86 | 9/10/88 |
| RCP-3 startup/shutdown | 3/14/86 | 9/10/88 |

| Transient | Date of First Recorded Unit 1 Event | Date of First Recorded Unit 2 Event |
|---|---|---|
| RCP-4 startup/shutdown | 3/14/86 | 9/10/88 |
| Turbine trip without reactor trip | 4/5/87 | 4/22/89 |
| Loss of offsite power | 3/28/87 | 7/20/89 |
| Loss of RCS flow in a loop at power | 1/17/88 | 3/20/90 |
| Auxiliary spray with $\Delta T > 320°F$ | 3/22/99 | 10/8/96 |
| Plant loading between 0% and 15% | 3/9/87 | 4/4/89 |
| Plant unloading loading between 0% and 15% | 3/9/87 | 4/7/89 |
| Refueling | 10/8/88 | 9/14/90 |
| Secondary side hydrostatic tests S/G-1 | 10/21/85 | 6/25/88 |
| Secondary side hydrostatic tests S/G-2 | 10/21/85 | 6/25/88 |
| Secondary side hydrostatic tests S/G-3 | 10/21/85 | 6/25/88 |
| Secondary side hydrostatic tests S/G-4 | 10/21/85 | 6/25/88 |
| Charging and Letdown Shutoff (Normal) | 1/11/89 | None |
| Charging Trip Prompt Return (Normal) | None | 10/9/96 |
| Charging Trip Delayed Return (Normal) | None | 4/26/92 |
| Letdown Trip Prompt Return (Normal) | 2/1/90 | 1/22/91 |
| Letdown Trip Delayed Return (Normal) | 12/22/88 | 11/1/90 |
| Charging and Letdown Shutoff (Alternate) | 8/27/87 | 10/7/88 |
| Charging Trip Prompt Return (Alternate) | 10/30/95 | 2/23/96 |
| Charging Trip Delayed Return (Alternate) | 11/25/02 | 10/23/88 |
| Letdown Trip Prompt Return (Alternate) | 12/10/87 | 10/3/88 |
| Letdown Trip Delayed Return (Alternate) | 7/28/87 | 5/17/88 |
| Reactor trip (with no cooldown) | 4/10/87 | 4/11/89 |
| Reactor trip (with cooldown and SI) | 2/2/94 | 6/9/98 |
| Inadvertent safety injection | None | 3/18/89 |
| Step-load decrease of 10 percent of full power | 7/7/86 | 9/24/88 |
| Step-load increase of 10 percent of full power | 7/7/86 | 9/24/88 |
| Large step-load decrease with steam dump | None | 1/8/91 |
| Feedwater cycling S/G 1 | 1/17/87 | 9/23/88 |
| Feedwater cycling S/G 2 | 7/7/87 | 9/23/88 |
| Feedwater cycling S/G 3 | 7/7/87 | 9/23/88 |
| Feedwater cycling S/G 4 | 7/7/87 | 9/23/88 |
| Turbine roll test | 7/7/86 | 9/23/88 |
| Control rod drop | 7/7/86 | 3/1/89 |
| Primary side hydrostatic test | 3/16/86 | 5/9/88 |

b. Transient projections are made using a weighting methodology that considers all cycles that have occurred but gives more weight to cycles that have occurred more recently than those that occurred many years ago. The cycle projection rate E', is computed as follows:

E' is calculated as $E' = (R1*LTW + R2*STW) / (LTW + STW)$, where:
R1 = total average rate of cycle accumulation = $(N_{now} - N_{init}) / (t_{now} - t_{init})$
R2 = short-term average rate of cycle accumulation = $(N_{now} - N_{ago}) / (t_{now} - t_{ago})$
$t_{init}$ = date/time associated with the start of cycle counting (*Y0*)

$t_{now}$ = date/time of latest day that has been processed
$t_{ago}$ = a time that was *NY* years prior to t_now
$N_{init}$ = configured initial cycle count for this event (usually 0)
$N_{now}$= computed current cycle count for this event
$N_{ago}$ = computed cycle count at time t_ago

*LTW (long-term weighting factor), STW (short-term weighting factor), Y0 (first year of plant operation)* and *NY (number of years for short term)* are configurable values that can be adjusted by the user).

The weighting factors were adjusted such that more importance is weighted to short term rates than long term rates. This reflects the assumption that the future rate of accumulation is better represented by recent history than the entire history. The following parameters were used in the forward projection:

Y0 = 1986 (Unit 1, first year of plant operation, i.e. first year of an RCS Heatup)
Y0 = 1988 (Unit 2, first year of plant operation, i.e. first year of an RCS Heatup)
LTW = 1.0
STW = 3.0 (placing more importance on short term weight than long term)
NY = 8 (Unit 1, based on approximate number of years of available FatiguePro data: 1998 - 2005)
NY = 11 (Unit 2, based on approximate number of years of available FatiguePro data: 1995 - 2005)

The projection methodology discussed above is provided from Structural Integrity Associates Calculation Package FP-VOG-315, Rev. 1, which is available for NRC review during the audit.

Weighting the short-term events more heavily is justified for several reasons. First, many of the cycles counted occurred significantly more often during the first several years of plant operation than they have since. VEGP cycle and fatigue projections are recalculated every 18 months (procedure 83101-C Section5.1.5) so a future increase in frequency of a given event will quickly result in a projected number of cycles that is higher than a traditional straight line average projection. In fact, of 82 cycles that have occurred at VEGP to date, only 35 would have a higher projection if weighting were not used.

Contrary to the way cycle and fatigue projections are normally weighted, the following table shows individual locations where the projection is done differently.

| Unit and Cycle | LTW | STW | NY |
|---|---|---|---|
| Unit 1 Letdown Trip Delayed (Alternate) | 0 | 3 | 8 |
| Unit 1 S/G-2 Secondary Hydro | 1 | 1 | 8 |
| Unit 1 S/G-3 Secondary Hydro | 1 | 1 | 5 |
| Unit 1 S/G-4 Secondary Hydro | 1 | 1 | 5 |
| Unit 2 RCP-1 Startup/Shutdown | 1 | 3 | 8 |
| Unit 2 RCP-2 Startup/Shutdown | 1 | 3 | 8 |
| Unit 2 RCP-3 Startup/Shutdown | 1 | 3 | 8 |
| Unit 2 Charging Trip Delayed (Alternate) | 1 | 3 | 8 |
| Unit 2 RCS Hydrostatic Test | 1 | 3 | 8 |
| Unit 2 S/G-1 Secondary Hydrostatic Test | 1 | 1 | 11 |

The resulting projection is not affected for the Secondary Hydrostatic Tests, the Unit 2 RCS Hydrostatic Test, or the Unit 2 Charging Trip Delayed (Alternate). The RCP startup/shutdown change results in the projection being reduced by 60 to 65 cycles. The worst case, the Unit 2 RCP-2 Startup/Shutdown with 583 cycles and 1000 allowed, still has plenty of margin if the projection is increased by 65 cycles. The Unit 1 Letdown Trip Delayed (Alternate) was weighted differently because the long term rate was believed to be unrealistic. There was a drastically different number of events counted manually from operator logs than proved to be present in time periods where FatiguePro data was present. So, the projection was based on recent accumulation of events. The projection is 22 cycles with only 20 allowed. Without the change, the projection would be approximately 30. There were 16 of these events before 1995 and only 1 since. It is believed that if data were available, most of the 16 pre-1995 events could be reclassified as Letdown Trip Prompt Return (Alternate), but the data is not available. This event primarily affects the CUF of the charging nozzles and they have been shown to have 60-year projected CUFs less than 1, with the affects of a reactor water environment considered. Therefore, even though the number of this design cycle is projected to exceed the design assumption, VEGP credits CUF monitoring of the charging nozzles to prevent the CUF from exceeding the ASME Code Limit of a CUF of 1.0. Because the projections are recalculated every 18 months and projections are performed for 40 and 60 years, any increase in transient rate would be identified long before the increase resulted in the CUF approaching the limit. Since the charging nozzles are evaluated for environmental effects, prior to the period of extended operation, the CUF limit for the charging nozzles will be reduced to 0.1316 to account for the $F_{en}$ value calculated for the charging nozzle environmental fatigue evaluation.

c. Westinghouse Report SE-ICAT(96)-212 describes how fatigue CUF prior to FatiguePro implementation was determined. In that report, Westinghouse calculated a current CUF as of 9/29/1995 for those locations monitored using stress-based monitoring, including the main feedwater nozzles. Baseline CUF for the main feedwater nozzles was calculated based on the number of transients experienced before 9/30/1995 and the main feedwater stress report. At the time FatiguePro was being upgraded for license renewal, Unit 1 FatiguePro data generated during the period of 9/30/95 through12/31/97 was not available so CUF of the main feedwater nozzles was assumed to accumulate during that period at the same rate it accumulated between 1/1/98 and 10/9/05. There was no such gap in data for Unit 2.

For the auxiliary feedwater nozzle, the CUF is primarily a function of the number of cold injections during periods of hot standby. Call the period before FatiguePro data was available Period 1 and the period with available FatiguePro data Period 2. Because the cycle count on Feedwater Cycling is known for both periods, the CUF for Period 1 was calculated based on a ratio of the results.

$$U_1 = U_{inc} \times E_1/E_2$$

Where:

$U_1$ = Initial fatigue prior to start of FatiguePro analysis (i.e., at 1/1/98 for Unit 1 and 6/30/95 for Unit 2), representing CUF for Period 1
$U_{inc}$ = Incremental fatigue usage computed by FatiguePro for Period 2
$E_1$ = Number of Feedwater Cycling events during Period 1
$E_{12}$ = Number of Feedwater Cycling events during Period 2

For the charging nozzles, Westinghouse Report SE-ICAT(96)-212 listed each loss of charging and loss of letdown event that occurred prior to 9/30/1995, but it did not specify whether normal or alternate charging was in service or what plant conditions were when the event occurred. Both units at VEGP operate on Alternate Charging during odd numbered cycles and on Normal Charging during even numbered cycles. Each pre-FatiguePro event was classified as occurring on either alternate or normal charging. Operator logs were reviewed to determine what mode the plant was in when each event in the report occurred and what the RCS temperature was during Mode 3 and 4 events. Events that occurred when the plant was in Mode 5 or 6 were deleted because the RCS temperature was less than 200°F. Mode 4 and low RCS temperature Mode 3 Loss of Letdown Delayed Return events were grouped together and counted as a separate event from Loss of Letdown Delayed Return events at normal operating temperature. FatiguePro was used to analyze the loss of charging and loss of letdown events since FatiguePro was implemented and determine an average CUF for each type of event. The average CUF per event was computed for each event based on averages of both nozzles and both units. This was necessary in part because Unit 1 FatiguePro data did not show any examples of the worst case event (loss of letdown with delayed return) but many were counted by Westinghouse for the pre-FatiguePro period. A small amount of fatigue calculated by FatiguePro for the charging nozzles was not attributed to loss of charging or loss of letdown events. An accumulation rate was calculated for the period with FatiguePro data and that rate was applied to the period before FatiguePro.

d. For RCS Leakage Tests, the Section XI Code, from the 1974 Code through the 2001 Edition, requires that the pressure be equal to the nominal operating pressure at 100% rated power. Westinghouse Design Standard1.3F, Rev. 0 defines the transient as:

> A leakage test will be performed after each opening of the primary system. During this test the primary system pressure is raised (for design purposes), to 2500 psia, with the system temperature above the minimum temperature imposed by reactor vessel ductility requiements, while the system is checked for leaks.
> In actual practice, the primary system will be pressurized to approximately 2400 psig, as measured at the pressurizer, to prevent the pressurizer safety valves from lifting during the leakage test. In addition, the secondary side of the steam generator must be pressurized so that the pressure differential across the tube sheet does not exceed 1600 psi. This is accomplished with steam, feedwater and blowdown lines closed off.
> For design purposes it is assumed that 200 cycles of this test will occur during the 40-year design life of the plant.

Any RCS leakage tests performed at a pressure higher than normal operating pressure will be counted and recorded in FatiguePro. However, actual leakage tests are performed by holding startup once the unit is at normal operating temperature and pressure and after the test, the plant resumes startup without depressurizing, unless a problem requiring cooldown and depressurization is found during the leakage test. If the plant cools down and depressurizes to make repairs, this will be counted as an RCS cooldown and subsequently as another RCS heatup. Therefore, FatiguePro does not, and should not, count leakage tests unless they are performed at greater than normal operating pressure.

e. As shown in Table 4.3.1-1 of the LRA, the design assumption is 60 cycles for the inadvertent safety injection transient. The zero projected cycles for Unit 1 shown in Table 4.3.1-2 of the LRA is the value calculated by the FatiguePro software. In the LRA, SNC manually changed projections that FatiguePro calculated as zero to one, but missed this particular cycle. The LRA will be amended to change this value to 1. The projected number of inadvertent safety injection

transients is not used in any baseline fatigue analysis. At VEGP, projected cycles and projected CUF are only used for comparison with design limits to determine if corrective action is needed.

A License Renewal Application amendment is required.

# Vogtle License Renewal Audit Questions and Answers

## TLAA Audit - 4.3-05

For Table 4.3.1-3, please describe how the Fen values in the Final Analysis Using Project CUF Calculated by FatigePro table were obtained. For Table 4.3.1-3, please describe how the Fen values in the Final Analysis Using Project CUF Calculated by FatigePro table were obtained.

## VEGP Response:

The $F_{en}$ values for the normal charging, alternate charging and safety injection nozzles were computed from actual plant events using the *Integrated Strain Rate* method as defined in EPRI TR-1003083, *Guidelines for Addressing Fatigue Environmental Effects in a License Renewal Application (MRP-47 Revision 1).* This method is summarized in the section below.

*Integrated Strain Rate*

A $F_{en}$ factor is computed at multiple points over the increasing (tensile) portion of the paired strain range, and an overall $F_{en}$ is integrated over the entire tensile portion of the strain range (i.e., from the algebraic lowest stress point of the maximum compressive stress event to the algebraic highest stress point of the maximum tensile stress event).

Under the above assumptions and referring to Figure 1, the Integrated Strain Rate $F_{en}$ is computed as:

$$F_{en} = \frac{\sum F_{en,i}\Delta\varepsilon_i}{\sum \Delta\varepsilon_i}$$

where: $F_{en,I}$ = $F_{en}$ computed at Point i, based on $\dot{\varepsilon}_i = 100\Delta\varepsilon_i/\Delta t$ and transformed parameters ($T^*$) and ($O^*$) computed using the respective Integrated Strain Rate approaches for each, discussed below.

| | | |
|---|---|---|
| $\Delta\varepsilon_i$ | = | change in strain at Point i, in/in |
| | = | $(\sigma_i - \sigma_{i-1})/E$ |
| $\sigma_i$ | = | stress intensity at Point i, psi |
| $\sigma_{i-1}$ | = | stress intensity at Point i-1, psi |
| $\Delta t$ | = | change in time at Point i, sec |
| | = | $t_i - t_{i-1}$ |
| E | = | Young's Modulus, psi, normally taken from the governing fatigue curve used for the fatigue evaluation. |

The summation is over the range from Point (3) to (4) and the range from Point (1) to (2). In the figure, Points (1) and (4) are assumed coincident. Point (4) is actually taken as the point where the stress returns to at least 90% of the steady state stress value. The strain discontinuity between this point and Point (1) is accounted for by omitting this increment from the total strain range in the denominator.

If two tensile transients are being ranged, the summation ranges from the algebraic minimum of the two Point (1)s to the algebraic maximum of the two Point (2)s. If two compressive transients are being ranged, the summation ranges from the algebraic minimum of the two Point (3)s to the algebraic maximum of the two Point (4)s. If a tensile transient is being ranged with itself (its 'zero' state), the summation ranges from Point (1) to Point (2). If a compressive transient is being ranged with itself (its 'zero' state), the summation ranges from Point (3) to Point (4) with Point (4) again taken where the stress returns to at least 90% of the steady state stress value.

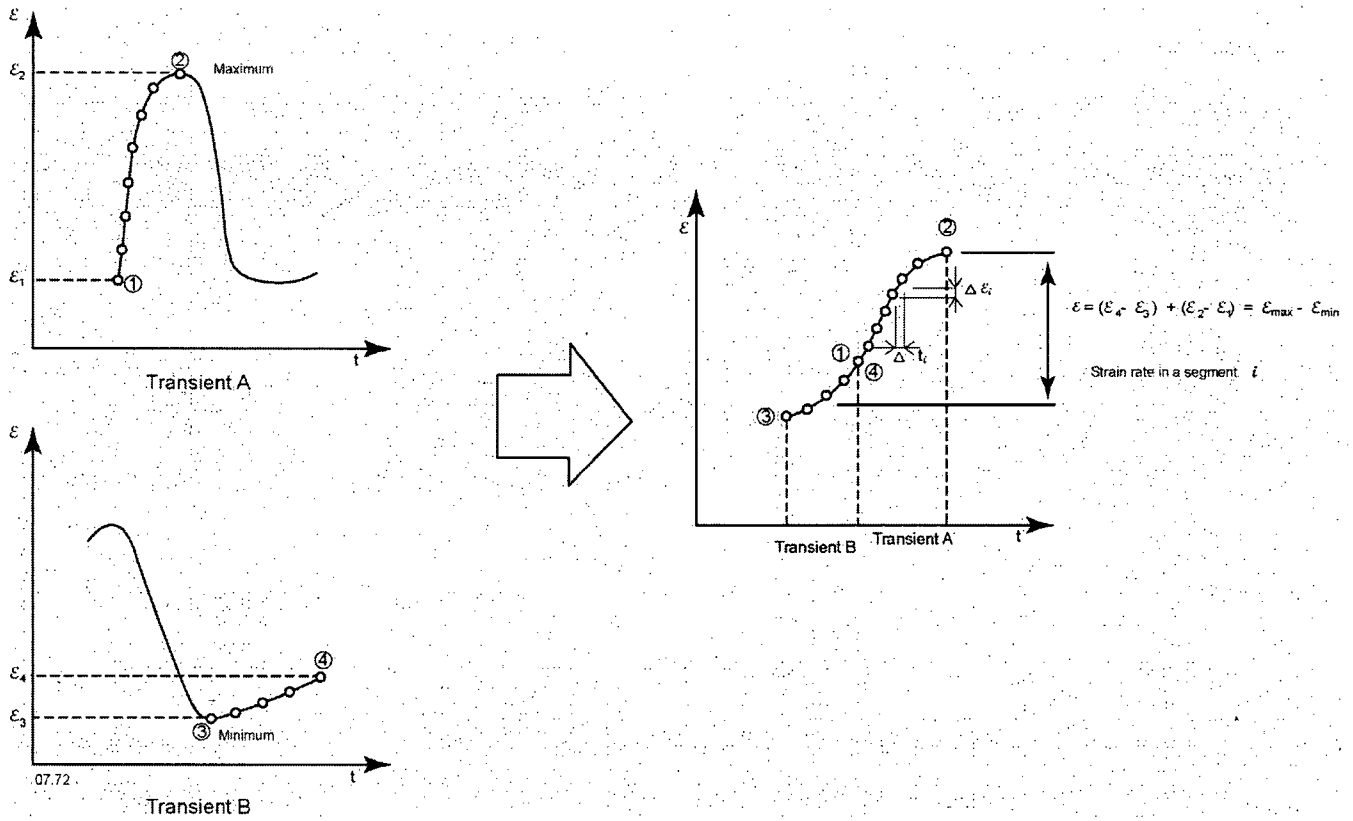


**Figure 1**

Detailed and Integrated Strain Rate Calculation

## TLAA Audit - 4.3-06

LRA section 4.3.1 states that cooldown/heatup cycles for Unit 1 and Unit 2 from 6/30/95 through 10/9/05 were analyzed to determine the average CUF. Please explain how this value was projected to the 60-year CUF. Please explain this for charging nozzles, safety injection nozzles, and RHR system Class 1 piping also.

## VEGP Response:

See the response to audit question 4.3-02 part b for the general projection methodology. The CUF projections used the same methodology as was used for the cycle counting projections, except the values of LTW and STW are not necessarily the same.

LRA section 4.3.1.5.3 concerns the environmentally assisted fatigue evaluation for the hot leg surge nozzle. For the hot leg surge nozzle, the average CUF per heatup/cooldown cycle was multiplied by the number of heatup/cooldown cycles that occurred prior to FatiguePro data being available to determine the CUF as of 12/31/97 on Unit 1 and as of 6/30/95 on Unit 2. Those values were then added to the CUF calculated for each unit since FatiguePro was implemented to determine the CUF value as of 10/9/05. The Unit 1 CUF value was 0.00238. The Unit 2 CUF value was 0.00205. Those values were then projected out to 60 years using the same methodology described in the response to audit question 4.3-2 part b, except that an LTW =0 and STW=1 were used. In this particular case, using an STW=3 and LTW=1 as was done for cycle counting would have slightly increased the projection for Unit 1 from 0.00534 to 0.00581 and the projection for Unit 2 from 0.00628 to 0.00660. An unweighted projection would have resulted in the Unit 1 projection being 0.00721 and the Unit 2 projection being 0.00692.

The VEGP FatiguePro software monitors the High-Head Safety Injection Nozzle as a cycle-based fatigue (CBF) location. This method introduces a significant level of conservatism in the fatigue computation, compared to the application of a stress-based fatigue (SBF) method, as it computes fatigue based on counted cycles according to the design basis fatigue evaluation. The fatigue accumulation was shown to be based on the counted safety injection events. In order to compute $F_{en}$ values, a stress analysis was performed using a simulated safety injection transient. A comparison of design features indicated the VEGP design is nearly identical to a sister plant that uses a FatiguePro SBF module to monitor fatigue of the same nozzle. FatiguePro was used to analyze a simulated safety injection event. A $F_{en}$ value was computed according to the same procedure described above in the response to audit question 4.3-5, and was shown to be 5.535. The allowable fatigue usage was then taken to be 1/5.535 = 0.18067. Projections use the same methodology as described in the response to audit question 4.3-2 part b. For this location, STW=3 and LTW=1 were used resulting in a projected CUF of 0.022 on Unit 1 and 0.150 on Unit 2. Using an unweighted projection would result in a higher projection of 0.045 in Unit 1 and a lower projection of 0.140 in Unit 2.

For the Accumulator/RHR Nozzle, the incremental fatigue since FatiguePro was determined to be essentially a function of the number of cooldowns on RHR. Pre-FatiguePro fatigue was calculated based on the incremental fatigue calculated by FatiguePro times the ratio of events before FatiguePro to the number of events since FatiguePro was implemented. Adding the pre-FatiguePro CUF to the incremental CUF calculated by FatiguePro results in the 10/9/05 values shown in the VEGP LRA. The 10/9/05 CUF was then projected to 60 years using the same methodology as described above for the Hot Leg Surge Nozzle.

The response to audit question 4.3-2 part c included a description of the method of calculating the 10/9/05 CUF for the Charging Nozzles. The method of projecting that baseline CUF to 60-years is the same as was described above for projecting the High-Head Safety Injection Nozzle CUF.

## TLAA Audit - 4.3-07

Section 4.3.5 of the LRA provides the replacement schedule for steam generator manway and handhole bolts. According to the Vogtle License Renewal Commitment List, this schedule may be changed due to an updated analyses initiated by the Bolting Integrity Program. Please explain why 10 CFR 54.21(c)(1)(iii) is used if these bolts' replacement schedule is dependent on future analyses.

## VEGP Response:

There is currently no plan to perform an analysis under the Bolting Integrity Program that could be used to change the scheduled replacement of steam generator manway and handhole bolts. However, should SNC decide at a later date to revise the replacement schedule of these bolts, an analysis would be performed to justify the revision.

To clarify this, Items 29 and 30 of the Future Action Commitment List will be amended to insert the word "potential" before "updated analyses."

An LRA Amendment is required to make conforming changes in Appendix A and Appendix B.

## TLAA Audit - 4.3-08

Basis Document (VEGP-LR-TLAA-307 page 24 and VEGP-LR-TE-018 page 6) state that LRA amendment is required to correct the LRA statement on the design basis of reactor vessel support. Please confirm the amendment will revise LRA section 4.3.4 from "Code of Record for VEGP as AISC 1969 version" to "ASME Code Section III. NF in accordance with UFSAR Table 3.2.2-1

## VEGP Response:

Per UFSAR Section 3.8.3.1.1, the VEGP RPV is supported by four seats under two hot leg and two cold leg nozzleswhich are spaced approximately 90° apart. The vertical loads are carried by the support seats to the embedded steel weldments under each support, while the radial and tangential loads are carried by the embedded steel weldments in the primary shield wall. Per UFSAR Section 3.8.3.4.1, The reactor pressure vessel supports embedded within the primary shield wall are procured in accordance with ASME Code, Section III, Division 1, Subsection NF; however, since they are outside the ASME Jurisdictional boundary, their design follows AISC specifications. Per UFSAR Section 3.8.3.2.1, both the 1969 version of the AISC Code and ASME Code, Section III, Division 1, Subsection NF apply to the supports. The license renewal application will be amended to specify that both codes apply.

A license renewal application amendment is required.

# Vogtle License Renewal Audit Questions and Answers

## TLAA Audit - 4.3-09

LRA Section 4.3.1.3 states, "The class 1 portions of the charging and letdown systems were analyzed for 20 cycles each of Letdown Trip with Delayed Return and Charging Trip with Prompt Return. Projected Cycles of these two transients are greater than design, however the magnitude of the transients and resultant fatigue contribution is smaller than in the design analysis."

Please explain how to draw the conclusion that the magnitude of the transients and resultant fatigue contribution is smaller than in the design analysis. Please provide all supporting documentation.

## VEGP Response:

While Charging Trip with Prompt Return results in a relatively small contribution to fatigue, the Letdown Trip with Delayed Return results is one of the more significant contributors to charging nozzle fatigue. Westinghouse System Standard Design Criteria 1.3X, Rev. 0, pages 3-37 and 3-38 (Westinghouse Proprietary) define the severity of both transients. Structural Integrity Associates Report FP-VOG-315, Rev. 1, pages 112, 117, 197, 198, 203, 215, 216, 217, and 219 (Includes some Westinghouse Proprietary information) are plots of actual Charging Trip with Prompt Return and Letdown Trip with Delayed Return. Comparison of the actual plots to the design transient show the temperature changes for actual events are less severe in magnitude and/or rate than the design transients. The increase in the number of cycles is small compared to the difference in severity between actual events and the design transients. Since the actual temperature changes are less severe than the design transients and the increase in events is small, it follows that the actual CUF is less than the design CUF.

The Westinghouse and Structural Integrity Associates reports mentioned above are available for NRC review during the audit.

## TLAA Audit - 4.3-10

Basis document (VEGP-LR-TLAA-307, page 17-19) states that the fatigue analysis related to letdown heat exchanger, containment cooler coil and MSIV are determined as TLAA. But, these TLAA are not discussed in the LRA. Please provide the details of these TLAA and plans to update the LRA.

## VEGP Response:

This response requires an LRA Amendment.

The following paragraphs will be appended to the end of LRA Sections 4.3.2:

There are non-Class 1 fatigue evaluations that use a different method of analysis than the 7000 cycles described above. In general, those evaluations use the same cycles, or a subset of the cycles, used for the Class 1 piping and therefore the existing analysis remains valid for 60 years because the cycles assumed will not be exceeded in 60 years.

One case is the analysis that addresses fatigue of the letdown heat exchangers. That analysis utilizes some of the primary piping transient events. The calculation demonstrates that a fatigue exemption applies to the heat exchanger and shows the damage factor for the heat exchanger bolting to be satisfactory with the ring spacer. The cycles assumed for both the heat exchanger and the bolting are bounded by the Class 1 piping cycles. Therefore, this analysis is determined to be a TLAA, but the analysis is already valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

Another case is the fatigue test report for containment cooler Copper-Nickel Alloy Cooling Coils. This test report evaluates, by experiment, the stress placed upon Cu-Ni coils due to 1500 thermal cycles over a 40-year design life. The transient cycles that most apply to the cooling coils are those of plant start-up and shutdown (when the containment experiences the greatest temperature change). The limits for RCS start-up and Shutdown (200 of both) will limit the cycles that the coolers see to much less than 1500 for 60 years. Therefore, this analysis is determined to be a TLAA, but the analysis is already valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

Another case is the fatigue analysis of the main steam isolation valves that uses the maximum number of cycles in specification AX4AR17 (2000 for 40 years). The calculation shows that for the maximum yoke stress as calculated, 10000 cycles are allowed. This is 5 times the minimum acceptable per the spec. The component fatigue is bounded by the piping fatigue, which is assured through limits on the number of piping cycles in the Fatigue Monitoring Program. Therefore, this analysis is determined to be a TLAA, but the analysis is already valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

A license renewal application amendment is required.

# Vogtle License Renewal Audit Questions and Answers

## TLAA Audit - 4.3-11

Basis document (VOG-01Q-301 Revision 1, EAF Analysis for Vogtle Nuclear Plant Units 1 and 2) provides the supporting information on the Fen values for the consideration of the environmental fatigue.

1) For the charging nozzle, the basis document (VOG-01Q-301, p12) states, "The fourth event was not discovered in any of the Vogtle FatiguePro Data, but its characteristics are assumed to be the same as one of the evaluated events." Please clarify what is the fourth event and "one of the evaluated events". Please explain the basis the characteristics of the both events are assumed to be the same.

2 For the SI nozzle, the basis document (VOG-01Q-301, p19) states that "simulated design basis event expected to be reasonably representative of the actual plant event" and FatiguePro was used to analyze a simulated safety injection event shown on Figure 2. Appendix B provides the analysis using "simulated transient for SI for Millsone-3". Please clarify if the transient shown in the Figure 2 as the input to the analysis for the Fen of SI nozzle.

3) Explain why Millstone's Fen is applicable to Vogtle. Include in the explanation consideration for the difference in ambient temperature.

## VEGP Response:

1) The fourth event is Charging Trip Delayed and the fifth event is Charging Trip Prompt. The Charging Trip Delayed event was assumed to be the same as the first event, Charging and Letdown Shutoff. As shown on pages 3-42 and 3-44 of Westinghouse Standard 1.3X, Rev. 0, the two events are nearly identical with the same temperature changes. Based on review of fatigue data from multiple plants, the Charging Trip Delayed and the Charging and Letdown Shutoff are essentially the same event and result in essentially the same fatigue usage since they both result in charging and letdown both being shutoff. Westinghouse Standard 1.3, Rev. 2 combines the two events into a single event for newer plants.

   Note Table 10-9 of VOG-01Q-315, rev. 1 for how these events were paired with $F_{en}$ values and that a maximum Fen of 15.35 is used for the Charging Trip Prompt event.

2) Yes, Figure 2 is the basis for the Fen evaluation for the SI Nozzle.

3) The Fen calculated was not Millstone's Fen, it was Vogtle's Fen. The Millstone model was used to simulate an event because their plant is also a 4 loop Westinghouse plant of the same vintage as Vogtle with the same nozzle design and the same design transient. The simulated event used the Vogtle ambient containment temperature instead of Millstone's ambient containment temperature.

## TLAA Audit - 4.3-12

LRA Section 4.3.1.6 and 4.3.1.7 states the TLAAs, "Full Structural Weld Overlays on Pressurizer Spray Nozzles, Safety, and Relief Nozzles and Surge Nozzle" and "High Energy Line-Break Postulated Locations Based on Fatigue Cumulative Usage Factor".
Please clarify, in the LRA, which method is chosen (10CFR54.21 (c) (i), (ii) or (iii)) to demonstrate the TLAAs for such as the LRA section 4.3.1.6 and 4.3.1.7. Please also provide a summary for these TLAAs.

## VEGP Response:

Qualification of the Full Structural Weld Overlays (FSWOL) on the Pressurizer Spray Nozzles, Safety and Relief Nozzles, and Surge Nozzles included a reconciliation of the existing fatigue evaluation for the limiting locations outside the FSWOL that meets the criteria as a TLAA. As stated in Section 4.3.1.6 of the VEGP LRA, it was demonstrated that the pressurizer nozzles would still meet the applicable ASME Code Section III requirements. The transient assumptions for this analysis are consistent with the existing stress analyses, which SNC has determined will not be exceeded during 60 years of operation. SNC will amend the VEGP LRA to include the following information at the end of Section 4.3.1.6:

> In summary, the recononciliation of the existing fatigue evaluation that was performed for the limiting locations outside the FSWOL is a TLAA that remains valid for the period of extended operation because the cycles assumed will not be exceeded during 60 years of operation. Therefore, this TLAA has been demonstrated to be acceptable for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

As stated in Section 4.3.1.7 of the VEGP LRA, all High Energy Line Break (HELB) analyses were shown to remain valid for the period of extended operation, with the possible exception of the Class 1 portion of the CVCS System, due to projections that some loss of charging and/or loss of letdown cycles may exceed the design assumption. The LRA stated, "For the charging line and letdown line transients, monitoring the CUF of the charging nozzles assures that all components in the Class 1 portion of the CVCS System continue to have a CUF less than 1.0. However, without additional review, this does not necessarily lead to the conclusion that the CUF of the components in the Class 1 portion of the CVCS System with a design CUF less than 0.1 will remain below 0.1." After the VEGP LRA was submitted, Westinghouse completed the additional review mentioned in the LRA. Westinghouse letter GP-18223 concluded that if the usage factor calculated for the nozzle subjected to operating transients is less than the design usage factor, it may be concluded that the adjacent class 1 auxiliary piping components' usage factors would be less than their design usage factors if evaluated for the same operating transients. SNC will also amend the VEGP LRA to replace the last two paragraphs of Section 4.3.1.7 with the following information:

> The normal and alternate charging nozzle design usage factors are 0.995. The maximum usage factors in the piping are 0.90 in Section 1, and 0.40 in Section 2. Based on the system design and operation, the actual operating transients in the piping and nozzles will be similar, consistent with the design transients. Therefore, it is reasonable to conclude that fatigue usage factors calculated for the RCL charging nozzles based on operating transients are bounding for the locations in the adjacent class 1 auxiliary piping. It is also reasonable to conclude that the magnitudes of fatigue usage of the various components will be related in a manner similar to those reported in the design reports.
>
> Therefore, if the usage factor calculated for the nozzle subjected to operating transients is less than the design usage factor, it may be concluded that the adjacent class 1 auxiliary piping

components' usage factors would be less than their design usage factors if evaluated for the same operating transients. Therefore, the existing HELB analyses for CVCS piping remain valid as long as the Fatigue Monitoring Program maintains the CUF of the charging nozzles less than or equal to 1.0 (see Section 4.3.1.5.4).

In summary, the existing VEGP HELB analyses have been shown to remain valid for the period of extended operation, except for the VEGP HELB analysis for CVCS piping which is maintained valid by the Fatigue Monitoring Program. Therefore, this TLAA has been demonstrated to be acceptable for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i) and 10 CFR 54.21(c)(1)(iii).

A License Renewal Application amendment is required.

## TLAA Audit - 4.3-13

LRA Section 4.3.2 states, "SNC evaluated the validity of the assumption of 7000 full-temperature thermal cycles for 60 years of plant operation. In general, the assumption was conservative and the actual temperature changes experienced by most systems were much less severe than the design full-temperature cycles. In some cases, the evaluation converted "partial-cycle" transients with an actual temperature change much less severe than that of the design full-temperature cycles to equivalent full-temperature thermal cycles (or, conversely, converted full-temperature cycles to an allowable number of partial-temperature cycles).

1) Please identify which plant systems experienced temperature changes greater than those assumed in the initial design. Also, explain how these cases were evaluated.
2) Please identify the systems that were evaluated using "partial cycles". Also, discuss how the expansion stress range for the partial cycles is evaluated.

## VEGP Response:

1) While the actual temperature changes for most systems were much less severe than the design full-temperature cycles, there were some systems where the actual temperature changes were only slightly less severe. No plant systems were identified that experienced temperature changes greater than those assumed in the initial design. The LRA will be amended to remove the term "In general," in the quoted text.

2) The LRA will be amended to remove the following text, "(or, conversely, converted full-temperature cycles to an allowable number of partial-temperature cycles)". Assuming that N=7000, $N_E$ is zero and only $N_1$ needs to be considered, the formula in LRA Section 4.3.2 can be solved for N or N can be assumed to be 7000 and the equation solved for $N_1$. The following systems were evaluated by assuming an actual temperature change and determining how many of those "partial cycles" would result in the same thermal expansion stress as 7000 full-temperature cycles using design temperature changes.

   - Charging pumps
   - Nuclear Service Cooling Water System
   - Gaseous Waste Processing
   - Drainage Systems
   - Reactor Makeup Water and Degasifier System
   - Turbine Plant Sampling System
   - Steam Generator Sample Coolers (Designed for 45,000 cycles)
   - Feedwater System
   - Auxiliary Feedwater
   - The following systems are mostly affected by changes in ambient room temperature, which was shown to be acceptable for 60 years of postulated daily temperature changes.
     - Compressed air
     - Auxiliary Gas System
     - Fire Protection
     - Diesel Fuel Oil
     - Demineralized Water
     - Hydrogen Control
     - Liquid Waste Processing

- Potable Water and Utility Water Systems
- Post Accident Sampling System (Gas Return Lines)
- Radiation Monitoring System (Not in-line Monitors)

The calculation that SNC performed for this evaluation is available for NRC review during the audit.

A License Renewal Application amendment is required.

## TLAA Audit - 4.3-14

Table 9-6 and 9-7 in the basis document (FP-VOG-315 Revision 1, Baseline Evaluation and 60-Year Projection of Vogtle-1/2 Plant Cycles, Fatigue Usage, and Environmental Fatigue Usage) provides the baseline and 60-year projection cycles. The 60-year projected cycles for the transient "Charging Trip Prompt (Normal)" for Unit 1 and transient "Charging and Letdown Shutoff (Normal)" for Unit 2 is zero in the Table 9-6 and 9-7.

Please provide the basis of 0 (zero) 60-year projected cycles in the table 9-6 and 9-7 and clarify if those values are used to calculate any projected CUF.

## VEGP Response:

The projected values in FP-VOG-315, Tables -6 and 9-7 were the actual projected values calculated by FatiguePro. As stated in the response to question 4.3.2, the projections in the LRA that FatiguePro showed as 0 were manually changed to 1 in the LRA, but the vendor who created the basis document was not asked to revise their FP-VOG-315. For the "Charging Trip Prompt (Normal)" and the "Charging and Letdown Shutoff (Normal)", the projected value is not used as an input to calculate any projected CUF. The only components with CUF monitoring that are potentially affected are the charging nozzles, the letdown nozzles, and the excess letdown nozzles. The Charging nozzle CUF is calculated using stress-based monitoring so projected cycles do not affect that calculation. Cycle-based monitoring is used for the other two nozzles but the Cycle-Based Fatigue Report Transient and Fatigue Monitoring System for Vogtle Electric Generating Plant Units 1 and 2, SIR-95-021, dated November 2005 shows that neither of these two transients is an input into that calculation.

SNC commits to revise the FatiguePro software to calculate a minimum projected value of 1 for any events that may potentially occur.

## TLAA Audit - 4.3-15

Section 4.3.6 of the LRA states the design cycles for the transients applicable to the reactor vessel internals were shown to be conservative. Considering some of the transients are projected to exceed design cycles, please justify why the current design cycles for reactor vessel internals is conservative.

## VEGP Response:

The only events that are projected to exceed design cycles at VEGP are feedwater cycling, letdown trip delayed and charging trip prompt. Feedwater cycling event provides a negligible contribution to the fatigue of the reactor vessel internals. The other two events are auxiliary transients and they are not considered in the fatigue evaluation of the reactor vessel internals. Therefore, the current design cycles for the reactor vessel internals are conservative.

## TLAA Audit - 4.7.2-1

LRA Section 4.7.2 identifies that the corrosion allowance analysis for the diesel fuel oil storage tank is a time-limited aging analysis for the application in accordance with 10 CFR 54.3, but does not provide any bases as to why the corrosion allowance analysis is an analysis that meets the definition for a TLAA in 10 CFR 54.3. The staff requests the following information relative to corrosion allowance analysis for the diesel fuel oil storage tank.

1. Provide the VEGP-specific or generic industry reference document that contains the corrosion allowance analysis for the diesel fuel oil storage tank.

2. Provide your basis as to why the corrosion allowance analysis for the diesel fuel oil storage tank is an analysis that meets the definition of a TLAA in 10 CFR 54.3. Include in your answer (to this part) an identification of the time-limited aging parameter that is relevant to this analysis.

3. Identify what the limiting acceptance criterion is for the amount of corrosion-related degradation that may be permitted to occur in the diesel fuel oil storage tank.

## VEGP Response:

1. The VEGP-specific corrosion allowance analysis for the diesel fuel oil storage tanks was provided to the Staff for review.

2. The corrosion allowance analysis for the diesel fuel oil storage tanks meets the definition of a TLAA as described in 10 CFR 54.3 as follows:

   (1) The diesel fuel oil storage tanks are in the scope of license renewal in accordance with 54.4(a).

   (2) The analysis considers the effects of aging, specifically corrosion of the buried carbon steel tanks exposed to the soil environment.

   (3) The analysis assumed a plant life of 40 years.

   (4) The analysis was used in a response to the NRC regarding Open Item 10 to the VEGP SER.

   (5) The analysis provided the basis for conclusions related to the capability of the diesel fuel oil storage tanks to perform their intended functions over the life of the plant in that the wall thickness of the tank would remain greater than required.

   (6) The corrosion allowance which was analyzed as being acceptable is considered in FSAR section 9.5.4.2.1.1.

3. The diesel fuel oil storage tanks were designed with an additional wall thickness of 1/8" for corrosion allowance. The analysis concludes that the estimated wall thickness loss due to corrosion does not exceed the 1/8" corrosion allowance and that the tanks remain capable of performing their intended functions during the life of the plant. Therefore the limiting acceptance criterion is that the calculated reduction of tank wall thickness must remain less than or equal to 1/8".

## TLAA Audit - 4.7.2-2

LRA Section 4.7.2 states that AMP B.3.4, Buried Piping and Tanks Inspection Program, will be used to manage any corrosion that occurs in the diesel fuel oil storage tank and that therefore the effect of corrosion on the intended function of the diesel fuel oil storage tank will be managed for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii). The staff's review of AMP B.3.4, Buried Piping and Tanks Inspection Program indicates that the AMP may not specifically schedule the diesel fuel oil storage tank for a buried tank inspection during the period of extended operation, and therefore may not provide adequate assurance that TLAA 4.7.2, Fuel Oil Storage Tank Corrosion Allowance, can be accepted in accordance with the provisions of 10 CFR 54.21(c)(1)(iii). Provide your basis as to why the Buried Piping and Tanks Inspection Program can be used as a basis for accepting the TLAA 4.7.2, Fuel Oil Storage Tank Corrosion Allowance, in accordance with 10 CFR 54.21(c)(1)(iii).

## VEGP Response:

LRA section 4.7.2 currently credits the Buried Piping and Tanks Inspection Program for managing loss of material due to corrosion from the external surfaces of the diesel fuel oil storage tank walls, and that the TLAA is acceptable in accordance with 10 CFR 54.21(c)(1)(iii). LRA section 4.7.2 will be amended to state that the analysis has been projected to the end of the period of extended operation. This projection shows that the wall loss due to corrosion would not exceed the additional wall thickness of either the piping or the tanks which was provided as a corrosion allowance. Therefore, this TLAA is acceptable in accordance with 10 CFR 54.21(c)(1)(ii).

SNC will continue to include the buried diesel fuel oil storage tanks and piping in the scope of the scope of the Buried Piping and Tanks Inspection Program as a conservative measure. Furthermore, the diesel fuel oil storage tanks are included in the scope of the One-Time Inspection Program, which will perform a volumetric inspection (UT) of tank wall thickness from the inside of a tank. SNC believes that the combination of the TLAA which concludes that the tank wall corrosion allowance will not be exceeded, the one-time tank wall thickness measurement, and inclusion of the diesel fuel oil storage tanks and piping in the Buried Piping and Tanks Inspection Program constitutes a multi-layered aging management strategy that provides a high degree of assurance that these tanks and piping will remain capable of performing their intended function during the period of extended operation.

A License Renewal Application amendment is required.

## TLAA Audit - 4.7-01

LRA Section 4.7.1 states, "For license renewal, SNC performed a TLAA evaluation of the primary loop analyses. SNC determined that no updates of the pressurizer surge line and Unit 2 RHR line LBB analyses were required for license renewal, since these do not contain CASS materials and since the transients assumed for 40 years are bounding for 60 years. SNC determined that RCL and the Unit 2 accumulator line analyses should be updated to account for the extended term, since CASS materials are present"

SRP 3.6.3 addresses, "LBB analyses should evaluate the material susceptibility to corrosion, the potential for high residual stresses, and environmental conditions that could lead to degradation by stress corrosion cracking. Primary water stress corrosion cracking (PWSCC) is considered to be an active degradation mechanisms in alloy 600/82/182 materials in pressurized in pressurized water reactor plants."

Please provide any plans to evaluate the original LBB analyses are needed to consider the evaluation the PWSCC susceptibility of the LBB-applied piping during the period of extended operation.

## VEGP Response:

The VEGP LBB analyses scope includes the Units 1 and 2 reactor coolant loop (RCL) piping (excluding branch line connections), the Unit 1 and 2 pressurizer surge lines, and the Unit 2 accumulator and residual heat removal (RHR) lines, as summarized in FSAR 3.6. There are no alloy 600/82/182 materials in the Unit 2 RHR line or the Unit 2 Accumulator Line so there is no need to address PWSCC susceptibility of the LBB-applied piping for those lines during the period of extended operation. The alloy 600/82/182 materials within the scope of these analyses are the Alloy 82/182 welds on the primary loop piping (at the reactor vessel inlet and outlet nozzle locations) and at the pressurizer surge line connection to the pressurizer nozzle. PWSCC susceptibility of the Alloy 82/182 welds for the LBB-applied piping during the period of extended operation has been addressed as follows.

As a part of the license renewal program, WCAP-10551-P, Addendum 1 performed a LBB evaluation for the Units 1 and 2 primary loop piping that explicitly addressed the PWSCC concern for the Alloy 82/182 welds in this piping. For the Alloy 82/182 welds in the pressurizer surge line, Full-Structural Weld Overlays (FSWOL) are being implemented under the existing 10 CFR 50 processes using Alloy 52/152 weld material, eliminating reliance on the Alloy 82/182 welds to mitigate the PWSCC concern. The Unit 2 pressurizer FSWOL was completed during the Spring 2007 outage. Pressurizer FSWOLs on Unit 1 are being implemented in the Spring 2008 refueling outage. As a part of the weld overlay program, LBB evaluations have been performed for the pressurizer surge lines considering the effects of the PWSCC.

SNC will verify the LBB evaluation in WCAP-10551-P, Addendum 1 meets the conditions of that process or have it re-performed using the acceptable process.

A License Renewal commitment is required.

## TLAA Audit - 4.7-02

LRA Section 4.7.1 states, "For license renewal, SNC performed a TLAA evaluation of the primary loop analyses. SNC determined that no updates of the pressurizer surge line and Unit 2 RHR line LBB analyses were required for license renewal, .."

But, the licensee stated that the existing LBB analyses will be confirmed remains valid, in response to the NRC's question on pressurizer FSOWL, dated on the January 3, 2007.

Provide any plans to confirm that LBB evaluation affected by the FSOWL remains valid during the period of extended operation.

## VEGP Response:

The reviewer's question refers to a statement from SNC letter NL-06-2768 dated January 3, 2007 concerning a request for NRC approval of a proposed alternative for application of pressurizer nozzle Full-Structural Weld Overlays (FSWOL) on VEGP Unit 2. These FSWOLs were completed during the Spring 2007 outage. Pressurizer FSWOLs on Unit 1 are being implemented in the Spring 2008 refueling outage. In the proposed alternative is the statement "The original leak-before-break (LBB) analyses will be confirmed to be valid after the weld overlays are applied, the amount of shrinkage is determined, and the shrinkage stresses are calculated."

Westinghouse letter GP-18216, dated August 2, 2007, documented that the amount of axial shrinkage on the pressurizer nozzle due to SWOL was determined. The shrinkage stress analysis concluded that there is no impact on the LBB input loads by the SWOL shrinkage effect. Westinghouse has performed an LBB evaluation (Westinghouse letter GP-18086 dated January 19, 2007) for the Vogtle Unit 2 pressurizer surge line and the results of the evaluation showed that the conclusions of the LBB shown in the WCAP-12218, WCAP- 12218 Supplement 1, and WCAP-12218 Supplement 2 remain valid after the SWOL application.

In summary, the existing LBB reports were reviewed and determined to remain valid for the period of extended operation because the surge line contains no CASS material and the transient assumptions used in the fatigue portion of that evaluation remain valid for 60 years operation (LRA Section 4.7.1). The FSWOL resolves any PWSCC concerns. SNC evaluation of the FSWOL for license renewal in VEGP-LR-TE-018 determined that the Fatigue Monitoring Program at VEGP is not affected by FSWOL (except for a potential need to revise the stress-based fatigue monitoring module for the surge nozzle that is addressed in LRA Section 4.3.1.6). Therefore, since the existing LBB for the surge lines has been determined valid for 60 years without considering FSWOL and FSWOL did not affect the existing LBB for the surge lines, LBB for the surge lines remains valid for 60 years operation with FSWOL considered.

The implementation of the FSWOLs is accomplished under the existing 10 CFR 50 processes. The period of extended operation will not impact the validity of the LBB analyses performed for the FSWOL effort.

# Vogtle License Renewal Audit Questions and Answers

## AMP Audit - B.3.0-01

In LRA AMP B.3.23, "Reactor Vessel Closure Head Stud Program," for program elements 3, 4, 5, and 6, the applicant states that VEGP Inservice Inspection Program for the 3rd inspection interval will use the 2001 Edition, inclusive of 2003 Addenda. The LRA further states that the program will be updated in conformance with 10 CFR 50.55a for future inspection intervals. Therefore, the applicant considers this as an exception to the GALL AMP XI.M3, "Reactor Head Closure Studs." However, staff does not consider this as an exception, since the ASME Code Section XI edition referenced in GALL AMP XI.M3 is also 2001 Edition of the ASME Code Section XI, inclusive of the 2003 Addenda. Please explain why the relevant statement on the Code Edition for the LRA AMPs is considered to be an exception to GALL AMP XI.M3, or clarify if the LRA needs to be amended to delete this exception based on the staff's determination. In addition, please identify all the AMPs that have similar exceptions and discuss your plans to amend the LRA.

## VEGP Response:

SNC understands it is the staff's interpretation that use of later Editions of ASME Section XI than the edition specified in NUREG-1801 Rev. 1 for future inspection intervals is not an exception to NUREG-1801, provided the Edition of ASME Section XI currently used is the same Edition referenced in NUREG-1801 Rev. 1.

As result of the staff's interpretation, SNC amends the VEGP license renewal application to remove this issue as an exception. Within the VEGP license renewal application, this issue is shown as an exception for the RCS CASS Fitting Evaluation Program (B.3.5), the One-Time Inspection Program for ASME Class 1 Small Bore Piping (Section B.3.18), and the Reactor Vessel Closure Stud Program (B.3.23). Specifically, the VEGP license renewal application is amended as follows:

Section B.3.5:
The "Exceptions to NUREG-1801" section of B.3.5 will be amended to read "None." The "Program Description" text for section B.3.5 will be amended to add the removed "Exception" text, along with the content of Note (1).

Section B.3.18:
The "Exceptions to NUREG-1801" section of B.3.18 will be amended to delete the second item in the exception table (associated with "6. Acceptance Criteria"). The "Program Description" text will be amended to add the "Exception" text removed from the exception table. Additionally, the program description text will be amended to clarify that the current ASME Section XI code of record for VEGP (3rd 10-year interval) is the 2001 Edition including the 2002 and 2003 Addenda.

Section B.3.23:
The "Exceptions to NUREG-1801" section of B.3.23 will be amended to revise the first line item in the exception table as follows:

> ~~*NUREG-1801, Section XI.M3, describes the program as conforming to the requirements of ASME Section XI, 2001 Edition including the 2002 and 2003 Addenda. However, 10 CFR 50.55a governs the application of Codes and Standards. While the VEGP Inservice Inspection Program for the 3rd inspection interval will use the 2001 Edition including the 2002 and 2003 Addenda, the program will be updated in conformance with 10 CFR 50.55a for future inspection intervals.*~~
>
> ~~*Additionally, v*~~*Volumetric examinations are in compliance with the performance demonstration*

*initiative. This initiative program is currently based on Appendix VIII, 2001 Edition of Section XI as mandated by 10 CFR 50.55a.*

*Th~~ese~~ differences ~~are~~ **is** considered to be an exception to NUREG-1801, Rev. 1, Section XI.M3.*

The "Program Description" text for VEGP license renewal application section B.3.23 will be amended to add the following text:

*NUREG-1801, Section XI.M3, describes the program as conforming to the requirements of ASME Section XI, 2001 Edition including the 2002 and 2003 Addenda. However, 10 CFR 50.55a governs the application of Codes and Standards. While the VEGP Inservice Inspection Program for the 3rd inspection interval will use the 2001 Edition including the 2002 and 2003 Addenda, the program will be updated in conformance with 10 CFR 50.55a for future inspection intervals.*

A license renewal application amendment is required.

## AMP Audit - B.3.3-01

The enhancement section of LRA AMP B.3.3, "Boric Acid Corrosion Control Program," states that the program scope and acceptance criteria will be enhanced to address the effects of borated water leakage on materials other than steels, including electrical components that are susceptible to boric acid corrosion. Please list the components that will be added to the scope of this program and materials that they are made of. Also, discuss the method for detection of aging effects, frequency of inspections, and acceptance criteria for evaluation of any detected borated water leakage or crystal buildup for these components.

## VEGP Response:

SNC has made a commitment to enhance the Boric Acid Corrosion Control Program (BACCP) to specifically include materials other than steels that are potentially susceptible to boric acid corrosion if exposed to boric acid leakage. Materials identified during the aging management review process other than steels were cast iron, copper alloys, and aluminum alloys.

The components subject to an aging management review (AMR) that are constructed of these materials and have a potential to be exposed to borated water leakage are predominantly fire protection components, misc. mechanical components (e.g., valves, drain bodies, housings, casings) and electrical connectors. The component types are identified in the VEGP LRA Section 3 AMR results tables for the following LRA systems: Fire Protection, Sampling System, Component Cooling Water System, Drain Systems, ECCS, Potable and Utility Water System, and Electrical Components. SNC notes that it is unnecessary to "add" specific components to the BACCP under this enhancement, only the additional materials. The BACCP scope is already configured to assess the potential corrosion of any components/ materials that are exposed to the borated water leakage path.

Detection of aging effects for these components due to borated water leakage or boric acid crystal residue is primarily through visual observation. When a boric acid leak is identified, a screening evaluation is performed to determine if a corrosion assessment is necessary. If corrosion is present, the corrective action process assesses the extent of the corrosion, the acceptability of continued service, and any required corrective actions.

Boric acid inspections are implemented through ISI activities (e.g., pressure testing), leakage assessments, and personnel performing routine work activities and plant walkdowns (operations, maintenance, health physics, engineering, BACCP owner performing program walkdowns, etc.). The frequency of these inspections and activities ensure timely detection of loss of material due to boric acid leakage.

## AMP Audit - B.3.3-02

The operating experience section of LRA AMP B.3.3,"Boric Acid Corrosion Control Program," states that "An assessment revealed that boric acid leaks had not been consistently identified and evaluated under the VEGP Boric Acid Program. Based on these findings, program enhancements were implemented to ensure that all boric acid leaks are identified with a condition report. Procedures were changed to clearly require personnel to write a condition report when boric acid leakage is discovered. Leaks outside of containment are flagged in the field with a problem marker."

a. Discuss your process for reviewing all VEGP-specific and generic boric acid leakage experience. Discuss how this process is used to incorporate such experience into the scope of the Boric Acid Corrosion Control Program and schedule the relevant system locations for boric acid leakage examinations.
b. Clarify whether the VEGP-specific responses to applicable NRC's generic communications and orders on boric acid leakage or corrosion (including, Bulletin 2003-02, Bulletin 2004-01, and First Revised OrderEA-03-009) are within the scope of your Boric Acid Corrosion Control Program.
c. Clarify whether any of the commitments made in response to these generic letters and orders are within the scope of the Boric Acid Corrosion Program.

## VEGP Response:

(a) Operating experience (OE) is continuously evaluated to determine any impact to aging effects and/or mechanisms managed by the Boric Acid Corrosion Control Program (BACCP). Plant-specific items such as condition reports, SNC Licensee Event Reports (LERs), SNC OE Alerts, etc., are reviewed for potential impact to the BACCP by the program owner. Industry events are likewise screened by the owner for applicability to the BACCP, including NRC generic communications, vendor communications, NUREG reports, INPO and WANO Operating Experience, EPRI and MRP reports, and Licensee Event Reports. Health reports are issued periodically on the BACCP, which take into consideration operating experience and trends.

(b) The VEGP-specific responses to the applicable NRC's generic communications and orders on boric acid leakage/corrosion are within the scope of the VEGP boric acid corrosion control program (BACCP). As a clarification, the BACCP is an integrated program that is coordinated with other site program activities. The BACCP uses the VEGP RCS Alloy 600 material inspection program as the current-term program vehicle for performing inspections of these nickel alloy component locations that are the subject of these NRC communications. For the period of extended operation, the Nickel Alloy Program for Reactor Vessel Closure Head Penetrations and the Nickel Alloy Program for Non-Reactor Vessel Closure Head Penetration Locations are the program vehicles for these implementing details and commitments. The Nickel Alloy Program for Reactor Vessel Closure Head Penetrations is an existing "subprogram" of the VEGP RCS Alloy 600 material inspection program. SNC expects that the Nickel Alloy Program for Non-Reactor Vessel Closure Head Penetration Locations will also be a "subprogram" of this existing nickel alloy material inspection program.

The Vogtle-specific responses to these NRC generic communications and orders and related documents are as follows.

1. NRC Bulletin 2003-02, "Leakage from Reactor Pressure Vessel Lower Head Penetrations and reactor Pressure Boundary Integrity"
   (a) NL-03-1958, Vogtle Electric Generating Plant Response to NRC Bulletin 2003-02,

September 19, 2003
(b)Letter from the NRC on Vogtle Electric Generating Plant Response to NRC Bulletin 2003-02, January 13, 2005 (NL-05-0144)

2. NRC Bulletin 2004-01, "Inspection of Alloy 82/182/600 Materials Used in the Fabrication of Pressurizer Penetrations and Steam Space Piping Connections at PWRs"
   (a) NL-04-1150, Response to NRC Bulletin 2004-01, July 26, 2004
   (b) NRC Staff Approval for Alternative for Application of Pressurizer Nozzle Full-Structural Weld Overlays, April 3, 2007 (NL-07-0795)
   (c) NL-07-1320, Proposed Alternative for Application of Pressurizer Nozzle Full-Structural Weld Overlays, July 24, 2007
   d) NL-07-1516, Vogtle Electric Generating Plant Unit 1 Mitigation of Alloy 82/182 Pressurizer Butt Welds in 2008, August 1, 2007

3. NRC First Revised Order, EA-03-009, "Issuance of First Revised Order Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactors," February 20, 2004.
   (a) ML052300617, Relaxation of Requirements Associated with First Revised Order (EA-03-009) Dated February 20, 2004, Relaxation Request, Examination Coverage for Reactor Pressure Vessel Head (SNC Letter No. NL-05-1672)
   (b) ML062360585, Relaxation of Requirements Associated with First Revised Order (EA-03-009) Dated February 20, 2004, Relaxation Request, Inspection Coverage Requirements (SNC Letter No. NL-06-1986)

(c) The following commitments made in response to these generic letters and orders are within the scope of the VEGP boric acid corrosion control program (BACCP):

1. NRC Bulletin 2003-02

The current basis for BMI inspections is found in MRP 2003-017, "Recommendations for PWR Owners with Alloy 600 Bottom Mounted Reactor Vessel Instrument Nozzles" letter dated June 23, 2003. NRC Bulletin 2003-02 requirements included a one-time visual inspection of all the nozzles penetrating the bottom head of the vessel and a general inspection of the bottom head for indication of wastage or corrosion of the low alloy steel vessel. The entire circumference of the interface of each nozzle with the vessel was visually examined for the presence of any deposits that might indicate leakage from the annulus between the nozzle and the vessel bottom head. This examination was completed during the Fall 2003 refueling outage for Unit 1 and during the Spring 2004 refueling outage for Unit 2, with no significant problems noted for either Unit.

SNC continues to participate in industry initiatives, such as the MRP Alloy 600 BMN blind demonstration project (MRP 2004-04), in which the reactor vessel bottom mounted nozzles (BMN) were inspected during the 10-year ISI.

Additional guidelines are forthcoming from the Issue Task Group for Alloy 600 on the inspection and evaluation to address PWSCC of bottom mounted nozzles. VEGP will adopt these guidelines when complete.

2. NRC Bulletin 2004-01

The Alloy 82/182 locations at VEGP associated with the pressurizer are the butt welds connecting stainless steel safe ends to: one 4" spray nozzle, four 6" Safety/Relief nozzles, and one 14" surge

nozzle for each unit. The regulatory requirements to ensure the integrity of the pressurizer and steam space piping connections are found in 10 CFR 50.55a which was utilized by SNC to plan and perform examinations utilizing the ASME Section XI Code as implemented in the ISI program. To supplement the ISI program, inspections for the butt welded pressurizer nozzle locations containing Alloy 82/182 material were performed in response to EPRI MRP 2003-039, issued January 20, 2004.

Mitigation applications, such as full structural weld overlays (FSWOLs) for Alloy 82/182 pressurizer butt welds, were proposed by the industry (MRP-139). These weld overlays, consisting of PWSCC-resistant welding material Alloy 52/152, are in the process of being applied at VEGP. The FSWOLs are expected to improve inspection coverage due to the complex geometry of the welds.

FSWOLs were applied on each of the six pressurizer nozzles on Vogtle Unit 2 during the Spring 2007 refueling outage. On Unit 1, SNC requested approval from the staff (NL-07-1516) to extend the mitigation actions beyond the December 31, 2007 industry (MRP-139) deadline. Currently, VEGP has a commitment to apply FSWOLs during the Spring 2008 refueling outage on Unit 1 (NL-07-0483). After such time, VEGP will fully satisfy the MRP-139 inspection/mitigation requirements for pressurizer Alloy 82/182 components (NL-07-1320/NL-07-1516).

3. NRC Order, EA-03-009

VEGP reactor vessel head inspections are performed in accordance with NRC Order, EA-03-009 dated February 13, 2003 and revised on February 20, 2004. This inspection includes one relief and one alternative to NRC First Revised Order 03-009 as allowed by Section IV.F of the Order and outlined below.

1. Order EA-03-009 Section IV.C(5)(a) specifies examination coverage for bare metal visual examination of the reactor vessel head surface. Full examination coverage is not possible without removal of reflective metal insulation. A minimum additional dose of 10 rem is expected to inspect the less than one percent of the vessel head surface obscured by the insulation. The obscured area is in an area where leakage is not expected to initiate. SNC requested relaxation from the staff to not inspect the small surface of the reactor vessel head obscured by insulation. This relaxation was granted by the staff in a September 2005 Safety Evaluation (Docket No. ML052300617).

2. Order EA-03-009 Section IV.C(5)(b) specifies examination volume for reactor vessel head penetration nozzle base material. Full examination volume coverage using ultrasonic testing is not possible at VEGP due to geometric considerations. Specifically, the bottom end of the nozzles are threaded, internally tapered, or both. This geometry makes ultrasonic inspection in accordance with NRC First Revised Order EA-03-009 a hardship based on the need to consider the increased radiation dose due to implementation of surface examination options. SNC proposed to the staff to ultrasonically test nozzle ends to the maximum extent possible. This alternate approach was approved by the staff in an August 2006 Safety Evaluation (Docket No. ML062360585).

## AMP Audit - B.3.4-01

Clarify how the one time inspection program for selective leaching will be coordinated (if at all) with the Buried Piping and Tanks Inspection Program when opportunistic inspections for buried pipe and tanks become available. If VEGP is crediting the Buried Piping and Tanks Inspection Program to manage selective leaching of buried cast iron components, clarify whether the AMP will actually perform an examination or inspection of the buried cast iron components. If AMP B.3.19 is credited for buried cast iron components, clarify how the AMP will inspect these components for selective leaching during the period of extended operation.

## VEGP Response:

The VEGP Buried Piping and Tanks Inspection Program is credited for managing loss of material due to general corrosion, crevice corrosion, pitting corrosion, microbiologically influenced corrosion, and galvanic corrosion from the external surfaces of buried cast iron fire hydrant components, piping components, and valve components. There are no inspections of internal component surfaces performed by this program. This program is not credited for managing loss of material due to selective leaching of buried gray cast iron components.

The One-Time Inspection Program for Selective Leaching is credited for managing loss of material due to selective leaching from both the internal and external surfaces of buried gray cast iron fire hydrant components and valve components. The in-scope buried cast iron fire protection piping components are not gray cast iron and therefore are not subject to selective leaching.

The One-Time Inspection Program for Selective Leaching is described in section B.3.19 of the license renewal application.

The VEGP Buried Piping and Tanks Inspection Program implementing procedures will include guidance to notify Engineering Support to have the One-Time Inspection Program for Selective Leaching program owner review excavations of the fire protection system to determine whether an opportunity exists to perform a selective leaching inspection on a gray cast iron component that is being exposed or replaced. If such an opportunity is determined to exist on a component that can be credited as meeting the requirements of the One-Time Inspection Program for Selective Leaching, it will be the option of the responsible site personnel to perform a selective leaching inspection. Once the requirements of the One-Time Inspection Program for Selective Leaching are fulfilled, no further selective leaching inspections would be performed under that program.

## AMP Audit - B.3.4-02

GALL AMP XI.M34, "Buried Piping and Tanks Inspection," recommends that the "corrective actions," confirmation process," and "administrative controls" program elements for this AMP be implemented in accordance with a facility's 10 CFR Part 50, Appendix B program. Explain if all the underground piping managed by the LRA Section B.3.4, Buried Piping and Tanks Inspection Program is safety related. Clarify how the "corrective actions," confirmation process," and "administrative controls" program elements for AMP B.3.4 will be implemented, in accordance with the VEGP 10 CFR Part 50, Appendix B Quality Assurance Program, for those buried piping or tanks that are within the scope of license renewal but are not categorized as safety related.

## VEGP Response:

Portions of the buried piping that are in scope for license renewal are non-safety related, including the NSCW sample piping and the feedwater piping to and from the condensate storage tanks which are in scope for 54.4 (a)(2), and fire protection piping which is in scope for 54.4 (a)(3).

Section B.1.3 of the license renewal application describes the implementation of the "corrective actions," "confirmation process," and "administrative controls" program elements for both safety related and non-safety related components for systems, structures, and components that are subject to an aging management review for license renewal. SNC's approach was audited by the NRC during the License Renewal Scoping and Screening Methodology Audit.

## AMP Audit - B.3.4-03

It is stated in LRA Section B.3.4, Buried Piping and Tanks Inspection Program, under program element Operating Experience that the only leaks identified from buried components in the scope of license renewal were in buried fire protection components. These leaks were typically attributed to design, installation, or operational issues, and not age related. Quantify the number of leaks identified in the buried fire protection system and identify the type of components affected. Discuss the number of leaks attributed to design, installation, or operational issues and the number of leaks attributed to age-related degradation and characterize the root causes of the leaking fire protection components. If any of the leaks have resulted from age-related aging, provide your basis for not crediting a periodic inspection-based program to manage the effects of aging on the intended functions of the impacted buried fire protection components for the period of extended operation.

## VEGP Response:

From 1999 through 2006, eight leaks were identified in fire protection system buried piping, including:

- two installation errors (bolt left out of a pipe flange, pipe sections misaligned)
- one pipe damaged during excavation of an adjacent storm drain
- one leaking gaskets at pipe elbow
- one pipe break due to a water hammer event
- three leaks with no cause documented

In addition, one leak has been identified but has not yet been excavated, so neither the source of the leak its cause have been determined. This leak is noted here because sampling of water from the leak indicates that it could be from fire protection.

A Root Cause and Corrective Action (RCCA) determination is documented for condition report 2004003901. That condition report describes a fire protection pipe break due to a water hammer event. The apparent causes of this event were identified as unusual plant conditions or configuration (fire protection surveillance in progress) and equipment not designed for the operating conditions (modification created an extended dead leg of buried piping susceptible to water hammer). An RCCA determination is not documented for the remaining fire protection leaks.

No leaks have been attributed to age-related degradation. In addition, inspections done on pipe segments replaced in 1999, 2003 and 2004 (condition reports 1999000700, 2003000679 and 2004003901) did not identify either internal or external corrosion. Therefore a periodic inspection-based program is not warranted.

# Vogtle License Renewal Audit Questions and Answers

## AMP Audit - B.3.5-01

The program description section of LRA AMP B.3.5, "CASS RCS Fitting Evaluation," states that this program evaluates the susceptibility of CASS components to thermal aging based on the screening criteria (casting method, molybdenum content, and percent ferrite) in the Christopher Grimes letter dated May 19, 2000, which is recommended by the GALL Report. Please identify all CASS components that have been screened out from AMP B.3.5 based on these screening criteria and provide your bases (including relevant casting method information and Molybdenum and delta-ferrite content parameter value information) for excluding these components from the scope of the AMP.

## VEGP Response:

Reactor coolant loop pipe castings are centrifugally cast from CF8A (low Molybdenum) material. Using the criteria contained in the May 19, 2000 Grimes Letter, none of these castings are susceptible to significant thermal embrittlement, regardless of the casting Mo and delta Ferrite content. As a result, no additional effort is needed to identify specific CMTR data and evaluate these castings according to the screening criteria.

The VEGP reactor coolant loop elbow fitting castings are statically cast from CF8A (low Mo) material. that have been screened out from AMP B.3.5 based on the screening criteria provided in the Christopher Grimes letter dated May 19, 2000 are listed below, with pertinent casting data. Also shown in these tables is casting data for the Unit 1 and Unit 2 reactor coolant system castings that were not screening out of the program (the VEGP Unit 1 Loop 4 RCP inlet elbow and the VEGP Unit 2 Loop 1 RCP inlet elbow). Additionally, it is noted that the Mo content values shown in these tables were assumed at the max allowed by SA351 Grade CF8A in the absence of measured Mo content.

As stated in Section B.3.5 of the LRA and consistent with the May 19, 2000 Christopher Grimes letter, thermal embrittlement of CASS valve bodies and the pump casings is adequately managed by the existing ASME Section XI inservice inspection requirements; thus, these castings are not evaluated for thermal embrittlement by this AMP.

VEGP Unit 1 Statically Cast RCS Loop Elbow Fitting Data

| Matl Grade | Heat No. | %Mo | Ferrite | Screening Result |
|---|---|---|---|---|
| SA351 CF8A | 09241-1 | 0.5 | 13.57 | Non-Significant |
| SA351 CF8A | 08920-1 | 0.5 | 19.47 | Non-Significant |
| SA351 CF8A | 04606-3 | 0.5 | 11.46 | Non-Significant |
| SA351 CF8A | 04506-1 | 0.5 | 16.78 | Non-Significant |
| SA351 CF8A | 05239-2 | 0.5 | 19.28 | Non-Significant |
| SA351 CF8A | 05337-2 | 0.5 | 15.50 | Non-Significant |
| SA351 CF8A | 05239-3 | 0.5 | 19.28 | Non-Significant |
| SA351 CF8A | 05198-3 | 0.5 | 13.04 | Non-Significant |
| SA351 CF8A | 04464-2 | 0.5 | 19.90 | Non-Significant |
| SA351 CF8A | 04342-2 | 0.5 | 12.26 | Non-Significant |
| SA351 CF8A | 05618-2 | 0.5 | 17.01 | Non-Significant |
| SA351 CF8A | 04407-2 | 0.5 | 13.59 | Non-Significant |
| SA351 CF8A | 17434-1 | 0.5 | 15.06 | Non-Significant |
| SA351 CF8A | 04081-1 | 0.5 | 10.10 | Non-Significant |
| SA351 CF8A | 13561-1 | 0.5 | 17.48 | Non-Significant |

| | | | | |
|---|---|---|---|---|
| SA351 CF8A | 13713-1 | 0.5 | 16.79 | Non-Significant |
| SA351 CF8A | 13565-1 | 0.5 | 11.85 | Non-Significant |
| SA351 CF8A | 17576-1 | 0.5 | 18.29 | Non-Significant |
| SA351 CF8A | 16634-1 | 0.5 | 14.70 | Non-Significant |
| SA351 CF8A | 17657-1 | 0.5 | 21.34 | Significant |

VEGP Unit 2 Statically Cast RCS Loop Elbow Fitting Data

| Matl Grade | Heat No. | %Mo | Ferrite | Screening Result |
|---|---|---|---|---|
| SA351 CF8A | 03631-2 | 0.50 | 9.79 | Non-Significant |
| SA351 CF8A | 15320-1 | 0.50 | 12.12 | Non-Significant |
| SA351 CF8A | 03109-2 | 0.50 | 14.09 | Non-Significant |
| SA351 CF8A | 08936-1 | 0.50 | 13.28 | Non-Significant |
| SA351 CF8A | 10058-2 | 0.50 | 12.86 | Non-Significant |
| SA351 CF8A | 11008-1 | 0.50 | 12.10 | Non-Significant |
| SA351 CF8A | 10327-2 | 0.50 | 11.82 | Non-Significant |
| SA351 CF8A | 05198-2 | 0.50 | 13.04 | Non-Significant |
| SA351 CF8A | 05618-1 | 0.50 | 17.01 | Non-Significant |
| SA351 CF8A | 09570-2 | 0.50 | 19.46 | Non-Significant |
| SA351 CF8A | 09570-1 | 0.50 | 19.46 | Non-Significant |
| SA351 CF8A | 10058-4 | 0.50 | 12.86 | Non-Significant |
| SA351 CF8A | 12944-1 | 0.50 | 15.53 | Non-Significant |
| SA351 CF8A | 14857-1 | 0.50 | 16.99 | Non-Significant |
| SA351 CF8A | 14727-1 | 0.50 | 13.36 | Non-Significant |
| SA351 CF8A | 17737-1 | 0.50 | 17.97 | Non-Significant |
| SA351 CF8A | 18841-1 | 0.50 | 21.45 | Significant |
| SA351 CF8A | 18838-1 | 0.50 | 11.20 | Non-Significant |
| SA351 CF8A | 18848-1 | 0.50 | 12.20 | Non-Significant |
| SA351 CF8A | 19062-1 | 0.50 | 12.93 | Non-Significant |

VEGP Unit 1 Statically Cast SIS Accumulator 45 x 10" Laterals

| Matl Grade | Heat No. | %Mo | Ferrite | Screening Result |
|---|---|---|---|---|
| SA351 CF8A | 85047-2 | 0.50 | 11.37 | Non-Significant |
| SA351 CF8A | 96287-3 | 0.50 | 10.54 | Non-Significant |
| SA351 CF8A | 96278-4 | 0.50 | 10.54 | Non-Significant |
| SA351 CF8A | 86434-3 | 0.50 | 8.74 | Non-Significant |

VEGP Unit 2 Statically Cast SIS Accumulator 45 x 10" Laterals

| Matl Grade | Heat No. | %Mo | Ferrite | Screening Result |
|---|---|---|---|---|
| SA351 CF8A | 03953-3 | 0.50 | 14.03 | Non-Significant |
| SA351 CF8A | 03863-3 | 0.50 | 14.03 | Non-Significant |
| SA351 CF8A | 04464-4 | 0.50 | 18.61 | Non-Significant |
| SA351 CF8A | 03950-4 | 0.50 | 11.55 | Non-Significant |

## AMP Audit - B.3.5-02

LRA, Section B.3.5, "CASS RCS Fitting Evaluation," under program description section states that this program will not include the cast austenitic stainless steel bottom mounted instrumentation column cruciforms. These reactor vessel internals components are managed by the Reactor Vessel Internals Program. However, GALL XI.M12 AMP, "Thermal Aging Embrittlement Of Cast Austenitic Stainless Steel," "Scope of Program" Section states that the screening criteria [set forth in Christopher Grimes, NRC letter dated May 19, 2000] are applicable to all primary pressure boundary and reactor vessel internal components constructed from certain materials with service condition above 250°C (482°F).

a. Explain why exclusion of bottom mounted instrumentation column cruciforms from being in scope of LRA B.3.5 is not considered as an exception to GALL XI.M12 AMP.
b. Discuss what screening criteria are applied for CASS reactor internals in the VEGP Reactor Vessel Internals Program and provide technical justification for the reactor internal components that have been screened out based on these criteria

## VEGP Response:

SNC understands that NUREG-1801 Rev. 1 Section XI.M12 is applicable to pressure boundary components only and not reactor vessel internals. NUREG-1801 Rev. 1 Section XI.M13, "Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)" is the NUREG-1801 Program addressing loss of fracture toughness reactor vessel internals.

As described in VEGP LRA Table 3.1.1, Item 80, embrittlement of the VEGP Bottom Mounted Instrumentation Column Cruciforms is not addressed by LRA B.3.5 "CASS RCS Fitting Evaluation" or by a VEGP program compared to NUREG-1801 Rev. 1 Section XI.M13. Instead, VEGP credits the Reactor Vessel Internals Program to manage embrittlement of the cruciforms.

Aging management relies on the results of the ongoing EPRI Materials Reliability Program initiative to develop a comprehensive aging management program for PWR reactor internals. While the program implementation details have not yet been completed by EPRI, technical reports MRP-175 and MRP-191 describe the current approach being used by the EPRI MRP toward screening of components for aging management. Using the guidance contained in these EPRI MRP reports, the VEGP Bottom Mounted Column Cruciforms "screen in" for both thermal aging and irradiation embrittlement.

Regarding casting content, the VEGP Bottom Mounted Instrumentation Column Cruciforms are CF8 cast austenitic stainless steel. However, details of the ferrite and Mo content associated with each casting are not known. Therefore, the castings conservatively "screen in" for thermal aging. Regarding neutron fluence, the cruciform castings are projected to exceed both the $10^{17}$ n/cm$^2$ (E > 1MeV) fluence threshold in NUREG-1801 Rev. 1 Section XI.M13 and the 6.7 x $10^{20}$ n/cm$^2$ fluence threshold stated in MRP-175 and MRP-191. Therefore, the cruciform castings "screen in" for irradiation embrittlement.

Finally, the VEGP Reactor Vessel Internals Program includes a commitment to submit an inspection plan for staff review and approval not less than 24 months prior to entering the period of extended operation for VEGP Units 1 and 2. Therefore, VEGP implementation of the EPRI MRP program results will be reviewed and approved by the NRC staff prior to entering the period of extended operation for VEGP Units 1 and 2.

## AMP Audit - B.3.5-03

GALL XI.M12, Thermal Aging Embrittlment of Cast Austenitic Stainless Steel (CASS), under "detection of Aging effects" states that:

> "For pump casings and valve bodies and "not susceptible" piping, no additional inspection or evaluations are required to demonstrate that the material has adequate fracture toughness. For potentially susceptible" piping, because the base metal does not receive periodic inspection per ASME Section XI, the CASS AMP provides for volumetric examination of the base metal, with the scope of inspection covering the portions determined to be limiting from the standpoint of applied stress, operating time, and environmental considerations. Examinations methods that meet the criteria of the ASME Section XI, Appendix VIII, are acceptable. Alternatively, a plant- or component-specific flaw tolerance evaluation, using specific geometry and stress information, can be used to demonstrate that the thermally-embrittled material has adequate toughness."

The staff has noted that the VEGP CASS RCS Fitting Evaluation Program does not propose any inspections of the susceptible CASS piping components (CASS elbows) that have been screened in as being susceptible to thermal aging; nor has VEGP provided indication that a flaw tolerance analysis has been completed for these components, as performed in accordance with the alternative GALL recommendation. The staff has also noted that the LRA neither includes any exception on the "Detection of Aging Effects" program element in GALL AMP XI.M12 to justify their deviation from the GALL recommendations; nor the LRA includes an enhancement of the program, with an associated LRA commitment, to make the "Detection of Aging Effects" program element consistent with the "Detection of Aging Effects" program element in GALL AMP XI.M12.

Please clarify, if VEGP has performed any plant-specific flaw tolerance on the CASS piping components that have been determined to be susceptible to thermal aging to demonstrate that the CASS materials have adequate fracture toughness. If not, explain why an enhancement or exception is not required to make the "Detection of Aging Effect" program element for the VEGP AMP B.3.5 consistent with the corresponding program element in GALL AMP XI.M12.

## VEGP Response:

The CASS RCS Fitting Evaluation Program is a new program which will be implemented prior to entering the period of extended operation. This new program has not yet been implemented and accordingly flaw tolerance evaluations of CASS piping component has not yet been performed.

No exception is taken regarding the "Detection of Aging Effects" element in NUREG-1801 Rev. 1 Section XI.M12 because VEGP intends to be consistent with this program element and will either perform examinations of susceptible castings or will develop plant or component specific flaw tolerance evaluations using specific geometry and stress information to demonstrate that the castings have adequate toughness.

## AMP Audit - B.3.6-01

The first exception in LRA AMP B.3.6 for program element "preventive actions" states that VEGP AMP is based on EPRI 1007820 guidelines instead of EPRI 107396 guidelines as recommended in GALL AMP XI.M21. Please clarify how EPRI Report No. 1007820 differs from EPRI Report No.107396 in its recommendations for preventive actions program element, and provide your basis why the preventive actions described in EPRI 1007820 are considered acceptable for managing corrosion and stress corrosion cracking in the closed-cycle cooling water systems.

## VEGP Response:

EPRI 1007820, "Closed Cycle Cooling Water Chemistry Guideline," Revision 1 supersedes EPRI TR-107396, "Closed Cycle Cooling Water Chemistry Guideline," Revision 0. Revision 0 outlined broad chemistry control strategies and provided only typical ranges for control parameters. Revision 1 includes normal ranges for control parameters, extends allowable corrosion inhibitor concentrations, and establishes well defined action levels.

All VEGP closed-cycle cooling water systems included within the scope of license renewal currently use nitrite / azole based corrosion control. For a nitrite based program, the differences between the Revision 0 and Revision 1 are as follows:

- Revision 1 extends the upper end of the Nitrite corrosion inhibitor control parameter range. The typical control range for nitrite in Revision 0 was 500 - 1000 ppm. The normal control range for nitrite in Revision 1 is 500 - 1500 ppm. In addition, action levels are implemented for Nitrite. Action Level 1 is defined as a Nitrite concentration less than 500 ppm. Action Level 2 is defined as a Nitrite concentration less than 300 ppm or greater than 4000 ppm.

- Revision 1 extends the upper end of the Azole control parameter range. The typical control range for Azoles in Revision 0 was 5 to 30 ppm. The normal control range for Azoles in Revision 1 is 5 to 100 ppm (with Azole concentration to be in excess of 25 ppm if pH is in the range of 10.5 to 11.0). In addition, action levels are implemented for Azoles. Action Level 1 is defined as an Azole concentration less than 5 ppm. Action Level 2 is defined as an Azole concentration less than 3 ppm.

- Revision 1 extends the upper end of the pH control range. The typical pH control range in Revision 0 was 8.5 - 10.5. The normal pH control range in Revision 1 is 8.5 - 11.0. In addition, Action Levels are established for pH. Action Level 1 is defined as a pH less than 8.5 or greater than 11.0. Action Level 2 is defined as a pH less than 8.0 or greater than 11.5.

- Revision 1 formalizes the 10 ppm limit for Chlorides and Fluorides in systems containing stainless steels. Further, Revision 0 required Chloride and Fluoride monitoring when system temperatures exceed 180 F. Revision 1 requires Chloride and Fluoride monitoring when system temperatures exceed 150 F. In addition, an Action Level 2 is defined for Chloride or Fluoride concentrations greater than 10 ppm.

- Revision 1 re-categorizes dissolved oxygen and total organic content as "investigative parameters" instead of diagnostic parameters. Investigative parameters represent non-routine testing that can be used to respond to a problem or perceived problem. Investigative parameters are not typically used until an anomalous condition occurs. Additionally, Revision 1 clarifies that refrigerant, Calcium / Magnesium, and Sulfate are investigative parameters.

- Revision 1 specifies monitoring frequencies for Tier 1, Tier 2, and Intermittent Systems. Control parameters are monitored weekly in Tier 1 systems, Monthly in Tier 2 systems, and Monthly or as Operated in Intermittent Systems. Diagnostic parameter monitoring frequencies are specified based on the parameter and System Tier. Monitoring frequencies were not specified in Revision 0.

Revision 1 of the EPRI Closed Cooling Water Guidelines provides an acceptable basis for managing corrosion and SCC in closed cooling water system because the guidelines are developed using a consensus process and represent improved understanding of CCW system chemistry over time. Additionally, it can be seen from the changes described above that Revision 1 is a considerably more prescriptive guideline, which results in an improved application of chemistry controls.

Note: Action Level 1 denotes a condition where system chemistry control parameters are outside the normal operating levels. Action Level 2 denotes a more serious condition where materials degradation could be initiated if the parameter is not returned to within the control range.

## AMP Audit - B.3.6-02

The second exception in AMP B.3.6, Closed Cooling Water Program, for program elements "preventive actions," "detection of aging effects," "monitoring and trending," and "acceptance criteria" states that VEGP program is based on EPRI 100780 guidelines instead of EPRI 107396 guidelines as recommended in GALL AMP XI.M21 and that the program does not include performance or functional testing. GALL AMP XI.M21 cites heat exchanger heat transfer capability monitoring, flow monitoring, heat exchanger inlet and outlet temperature monitoring, and differential pressure monitoring as possible function or performance monitoring tests. Please clarify which corrosion monitoring techniques will be applied as part of this exception and provide your basis why corrosion monitoring alone is considered to be capable of managing aging for the period of extended operation without crediting any performance or functional tests, as is otherwise recommended in GALL AMP

## VEGP Response:

Corrosion monitoring aspects of the SNC Closed Cooling Water Program implemented to date include monitoring and trending iron and copper concentrations and limited corrosion coupon measurements.

Measurement of accumulated corrosion products such as iron and copper provide an indirect indication of system corrosion. Each system establishes normal concentrations of these corrosion products. Consequently, a specific not to exceed value cannot be assigned. Rather, it is the overall trends which provide meaningful information regarding system corrosion rates. Corrosion coupons are installed in the VEGP Turbine Plant Cooling Water System. Measurement of coupon weight loss is an effective means to assess corrosion rates.

As summarized in the enhancement subsection of LRA Section B.3.6, additional corrosion monitoring techniques will be implemented prior to the period of extended operation. Currently, the monitoring techniques being considered include electrochemical monitoring, such as linear polarization measurement or electrochemical noise corrosion rate monitoring, and corrosion inspections.

Electrochemical monitoring techniques are described in Section 8.1.1 of EPRI 1007820.

Corrosion inspection techniques, primarily in the form of visual inspections are described in Section 8.4.1 of EPRI 1007820. EPRI 1007820 notes that inspection planning, sample collection, and inspection documentation are important parts of the inspection process. Inspection techniques will vary depending on the component type being inspected (piping, valves, heat exchangers, pump casings, etc.). The SNC response to audit question B.3.6-3 provides additional detail regarding the SNC approach toward identification of component locations for inspection.

While NUREG-1801 Section XI.M21 endorses performance and functional testing with EPRI TR-107396 as a basis, neither EPRI TR-107396, nor EPRI 1007820 conclude that performance or functional testing are effective for detection of passive component aging effects. Section 5.7.4 of EPRI TR-107396 and Section 8.4.4 of EPRI 1007820 indicate that performance testing is primarily of value with regard to monitoring of heat transfer reductions. However, both EPRI documents also recognize that performance monitoring is typically part of an engineering program. In most cases, functional and performance testing verifies that component active functions can be accomplished and such would be governed by the maintenance rule (10 CFR 50.65). For example, corrosion cannot be detected by system performance testing.

## AMP Audit - B.3.6-03

AMP B.3.6, Closed Cooling Water Program, states that the program will be enhanced to "to indicate the components in each system that are most susceptible to various corrosion mechanisms and to ensure that corrosion monitoring is appropriately implemented." Provide your technical basis for ranking these components based on the susceptibility to corrosion mechanisms and clarify how the susceptibility ranking will be applied to the AMP in order to pick components for inspection.

## VEGP Response:

A reasonable assessment of system components most susceptible to corrosion can be developed using a fundamental understanding of corrosion principles associated with closed cooling water chemistries and review of system, plant, and industry operating experience.

Components located in stagnant regions or in systems that are infrequently operated and components with creviced regions are at greater risk for significant corrosion since adequate transport of corrosion inhibitors, pH buffering agents, and biocides to the component location may not occur and adequate transport of corrosion products away from the component may not occur. In these cases, inadequate corrosion film development, deposit formation, and increased microbiological activity could result in increased corrosion rates not consistent with observed corrosion rates for other portions of the system. Additionally, creviced areas could experience differential aeration, resulting in localized attack of material within the crevice.

Components located in higher temperature regions could experience higher corrosion rates due to the fundamental temperature dependence on corrosion rates.

Review of system and plant operating experience collected during the course of operations provides a valuable tool for use in estimating component locations most likely to be more susceptible to degradation mechanisms.

Finally, reviews of industry-wide operating experience, including chemistry history, inspection results, and repair histories, can provide valuable insights into the corrosion processes occurring within closed cooling water systems and can be incorporated into susceptibility evaluations for these systems.

Based on this response, SNC will enhance VEGP License Renewal future action commitment list item no. 6 as follows:

"Enhance Closed Cooling Water Program documents to indicate the components in each system that are most susceptible to various corrosion mechanisms and to ensure that corrosion monitoring is appropriately accomplished. This qualitative assessment will be based on an understanding of corrosion principles associated with closed cooling water chemistries and on review of system, plant, and industry operating experience. Parameters considered in the review will include system flow parameters (focusing on identification of stagnant regions and on intermittently operated systems), normal operating temperatures, and component geometries (e.g. creviced areas)."

## AMP Audit - B.3.8-01

The second exception in AMP B.3.8, External Surfaces Monitoring Program, for the "Scope of Program," "Detection of Aging," and "Monitoring and Trending" program elements, states that inaccessible surfaces of the inscope components for this AMP will be inspected when the component are made accessible for scheduled maintenance. Clarify how VEGP will monitor for aging in the inaccessible regions if the components are not made accessible for inspection based on a reasonable maintenance frequency. Provide your basis (if at all) when alternative methods (such as boroscope inspections or examinations by remote camera) will be implemented if the inaccessible regions are not made accessible in accordance with a reasonable maintenance frequency.

## VEGP Response:

The inaccessible areas which contain components in the scope of the External Surfaces Monitoring Program will be identified during preparation of the implementing procedures. These areas will be inspected when made accessible during maintenance or for other reasons, such as for system leakage tests performed under the inservice testing program. These are referred to as opportunistic inspections. In addition, these areas will be evaluated to ensure that accessible systems and components are constructed of the same materials and are exposed to the same or a more severe environment as the systems and components in the inaccessible area. The intent of this evaluation is to ensure that the aging effects on the accessible systems or components are indicative of the aging effects on the inaccessible systems and components. This provides a degree of assurance that components in the inaccessible area are not degrading faster than components which are accessible for inspection.

If an opportunistic inspection is not performed within the inspection interval established for that area, the inaccessible area will be inspected either by making the area accessible or by remote means. The determination as to whether the inspection will be performed by direct or remote visual techniques will be performed on a case-by-case basis. Factors which would be considered in this determination include radiation dose rates, other personnel safety considerations, size and configuration of the area to be inspected, and any other issues relevant to providing personnel access to the specific area in question.

An area which is determined to be inaccessible due to extreme personnel safety hazards, such as a very high radiation area, will be inspected only when made accessible during maintenance or for other reasons (opportunistic inspection), or if there is evidence of leakage in the area. These areas must meet the following criteria:

- the area must contain a hazard that prohibits personnel entry,
- the area must be sealed such that access with a borescope or other remote inspection device is impractical,
- there are a minimal number of components in the area that require inspection under this program,
- equipment that could be affected by leakage in the area is not required to achieve or maintain safe shutdown or respond to an accident (low safety significance),
- equipment that could be affected by leakage in the area can be readily isolated,
- the area is provided with leakage monitoring capability, and
- an evaluation determines that systems and components in an accessible area are constructed of the same materials and are exposed to the same or a more severe environment (applicable to the aging effect) as the systems and components in the inaccessible area.

The existence of leakage detection capability combined with the ability to isolate affected components ensures that leakage will be detected and isolated prior to loss of a component intended function. Applying this exclusion only in areas containing a minimal number of components that require inspection minimizes the potential for leakage. Use of this exclusion only in areas containing equipment that is of low safety significance minimizes the potential consequences of any leak. Therefore, exclusion of an area that meets the above criteria from periodic inspection is justified due to the hazard of performing the inspection exceeding the hazard from any possible leak.

## AMP Audit - B.3.8-02

With regard to your scope for AMP B.3.8, External Surfaces Monitoring Program, clarify whether the coatings on any external coated surfaces are within the scope of the AMP and are credited for aging management. If they are, clarify what type of inspection method and techniques will be implemented to monitor for flaking, peeling, blistering, delamination, cracking, discoloring, or other aging of the coatings during the period of extended operation.

## VEGP Response:

VEGP does not credit coatings for aging management. The protective effects of any coating are not credited when the aging effects requiring management are determined for the underlying component materials; therefore the scope of this program is established without regard for protective coatings. However, VEGP agrees that observation of the condition of the paint or coating is an effective method for identifying degradation of the underlying material. Therefore, monitoring of the condition of coatings will be included in the inspection criteria of the External Surfaces Monitoring Program along with the inspection criteria to monitor for degradation of the component materials. Visual inspections will be used to monitor for cracking, peeling, blistering, flaking, delamination, discoloration, or other signs of degradation.

## AMP Audit - B.3.8-03

The fourth exception in AMP B.3.8, External Surfaces Monitoring Program, for the "Scope of Program," "Preventative Actions," "Parameters Monitored/Inspected," "Detection of Aging Effects," "Monitoring and Trending," and "Acceptance Criteria" program elements states that the program does not include acceptance criteria from specific design standards as the basis for systems and components within the scope of the AMP. The corresponding program in GALL AMP XI.M36 states that the any relevant indications of parameters called out by the "Parameters Monitored/Inspected" element of the AMP should be assessed against defined acceptance criteria for the each aging effect monitored for by the AMP. The GALL AMP identifies that design standards, procedural requirements, current licensing basis acceptance criteria, industry codes and standards, and acceptance standards in applicable engineering evaluations are acceptable source bases for establishing the acceptance standards for the components. Provide your basis why AMP B.3.8, External Surfaces Monitoring Program, does not include specific acceptance criteria for each of the aging effects monitored for by the AMP, as based on one or more recommended source documents in "acceptance criteria" program element of GALL AMP XI.M36.

## VEGP Response:

This exception was included to clarify that the VEGP External Surfaces Monitoring Program will not include specific quantitative acceptance criteria derived from design standards or industry codes such as the ASME Boiler & Pressure Vessel Code. The scope of this program will include a wide range of systems covered by ASME Class 2, ASME Class 3, ANSI B.31.1, National Fire Protection Association, American Water Works Association, plumbing, and manufacturer's codes and standards in a variety of pipe and component sizes. Therefore, specific quantitative acceptance criteria (ex.: minimum pipe wall thickness) for each of the thousands of pipe spools and other components in the scope of the program will not be included in implementing procedures for practical considerations. The inspections will be focused on identifying qualitative indications of corrosion. These general visual inspections are unacceptable if they identify indications such as loss of material, fluid leakage, cracking, missing or damaged insulation, damaged coatings, fretting of tubing, or other visible indications of aging, or that conditions exist which could promote aging. These qualitative acceptance criteria are consistent with industry standards as described in the following EPRI technical reports: EPRI TR-104514, "How to Conduct Material Condition Inspections," EPRI TR-1007933, "Aging Assessment Field Guide," EPRI TR-1009743, "Aging Identification and Assessment Checklist." The quantitative evaluation of deficient conditions, such as comparison of pipe wall thickness with code minimum allowable, will be performed as part of the corrective action process initiated by a Condition Report (CR). The CR will identify the specific system and location to be evaluated, so the applicable codes or standards can be readily determined to support the evaluation of the deficient condition and the determination of corrective actions that will be performed in accordance with the corrective action process.

## AMP Audit - B.3.9-01

In LRA AMP B.3.9, "Fire Protection Program," the applicant identifies an exception to the "parameters monitored/inspected," and "detection of aging effects," program elements regarding performance testing of fixed Halon fire suppression system. The exception states that performance testing of the fixed Halon fire suppression system is performed at 18 month intervals rather than at least once every 6 months as specified by NUREG-1801, SectionXI.M26. Please provide technical justification why the proposed testing frequency is acceptable to detect degradation of the halon fire suppression system before the loss of the component's intended function.

## VEGP Response:

VEGP's Fire Protection Program has an exception to XI.M26. Performance testing of the fixed Halon fire suppression system is performed at 18 month intervals rather than at least once every 6 months as specified by NUREG-1801, Section XI.M26. However, based on operating experience, VEGP's testing frequency of 18 months is adequate because there have been no age-related failures observed in the fixed Halon fire suppression system, which would agree with industry experience in the use of a dried gas. This testing frequency is considered to be acceptable to detect degradation before loss of the component's intended function. Should a trend in degradation in system performance be observed, the Corrective Actions Program would be invoked which could include a stepped up functional testing frequency, depending on the results of the evaluation.

The current licensing bases (CLB) for performance testing of Vogtle's fixed Halon systems is found in FSAR Chapter 9.0, Table 9.5.1-10, paragraph 4.0, and is 18 months. This testing interval is based, in part, on the fact that all Vogtle fixed Halon systems are small, one room systems where all system piping is subjected to the same controlled atmospheric environment (no significant aging mechanisms present) and the fact that Vogtle utilizes an 18 month operating cycle between refueling outages. The 18 month Halon system performance testing frequency is intended to correspond to the fuel cycle outage frequency. In addition to performance testing, SNC performs visual inspections of the Halon systems for corrosion, physical damage, and nozzles free of corrosion and unobstructed, at 6 month intervals.

## AMP Audit - B.3.9-02

The LRA Section B.3.9 states that the VEGP Fire Protection Program will be enhanced to perform wall thickness evaluations on water suppression piping systems using non-intrusive volumetric testing or visual inspections to ensure that wall thicknesses are within acceptable limits, as specified by GALL AMP XI.M27. Please clarify the "visual inspections" mentioned above is visual inspection of the internal surface of the fire protection piping and are performed in accordance with the criteria specified in " detection of aging effects," program element in GALL AMP XI.M27.

## VEGP Response:

The VEGP Fire Protection Program will be enhanced to perform wall thickness evaluations on water suppression piping systems using non-intrusive volumetric testing or visual inspections during plant maintenance to ensure that wall thicknesses are within acceptable limits, as specified by GALL AMP XI.M27. "Visual inspections" refers to inspections of the internal surfaces of the fire protection piping during plant maintenance activities and will be performed in accordance with the criteria specified in "detection of aging effects" in GALL AMP XI.M27. GALL AMP XI.M27, "detection of aging effects" permits visual inspections only, if it can be demonstrated that the inspections are performed on a representative number of locations on a reasonable basis. In all likelihood, a combination of visual inspections and non-intrusive examinations will be used at VEGP.

# Vogtle License Renewal Audit Questions and Answers

## AMP Audit - B.3.10-01

The Flow-Accelerated Corrosion Program takes an exception to GALL AMP XI.M17, "Flow-Accelerated Corrosion," with respect to using visual examination (VT) methods in addition to ultrasonic test (UT) and radiography test (RT) examinations. The staff notes that VT methods are incapable of sizing flaws and therefore cannot be used to make wear rate or flaw growth predictions based on the examination results. RT examinations are capable of sizing along the length or width of a component but cannot size through the depth (thickness) of a component.

a. Clarify whether the intended exception is to state that visual examinations will be performed in lieu of UT or RT examination methods or in addition to UT or RT examination methods. If VT methods will be applied, clarify which VT method or methods could be applied to these examinations and clarify how the VT methods selected would be capable of sizing any FAC-induced loss or material or loss of material induced by other mechanisms (e.g. loss of material by cavitation, etc.) and making loss of material wear rate projections for the components without the need for follow-up examinations using ultrasonic testing techniques.

b. Clarify how an RT examination can be used to depth size any relevant flaw indications and make appropriate wear rate predications without the need for follow-up examinations using ultrasonic testing techniques.

c. Clarify why the exception states that a UT examination *may be used to confirm or quantify a VT inspection result* instead of *will be used to confirm or quantify a VT inspection result.*

## VEGP Response:

a) It is not intended to substitute visual for UT or RT exams. Visuals would provide additional information on those large-bore systems where it is practical (manways are provided, or maintenance to the pipe provides an opportunity). The visual exam would be similar to a VT-3, and are intended to detect any visible internal piping degradation. (Typical FAC degradation would be visible as tiger striping, divots, or polished low areas where no protective oxide remains.) Any indication of wall loss would be evaluated, either by direct measurement (such as a pit gauge) for localized wear, or by internal UT for more generalized wear (more typical of FAC). These methods will provide wear measurements consistent with the normal FAC UT readings and will be used with the standard FAC wear rate evaluations, as required.

b) RT exams for FAC are limited to pipe sizes for which a tangential view of both walls is shown on the film. This allows direct measurement of the pipe wall thickness, with appropriate correction factors for image enlargement on the film.

c) The result from the visual exam may be that there is no evidence of FAC or similar damage. In that case, no follow-up NDE would be needed. Any evidence of damage WOULD need to be quantified, as discussed in a).

## AMP Audit - B.3.10-02

The Flow-Accelerated Corrosion Program takes an exception to GALL AMP XI.M17, "Flow-Accelerated Corrosion," with respect to alternative inspection and acceptance criteria for in-scope carbon steel or low alloy steel components that cannot be modeled by CHECWORKS.

a. Clarify what type of wear rate projection, flaw growth, or engineering criteria will be used to determine whether such unmodeled in-scope piping systems or components will be scheduled for appropriate NDE examinations.

b. Clarify what type of NDE methods will be applied for the inspections of the unmodeled components within the scope of this AMP.

c. Clarify what type of engineering judgment criteria will be used to assess the inspection results for those unmodeled components that are scheduled and receive the NDE examinations identified in your response to Part B of this question.

## VEGP Response:

a) Systems which cannot be modeled are compared to the susceptibility criteria of EPRI Report 1011838 (NSAC-202L-R3). For systems which are considered to be susceptible to FAC, a sample of components in each system is selected for inspection based on known problem areas (such as pressure drops, changes in direction, and splitting or combining flows).

b) The same NDE methods are applied for modeled and unmodeled components (primarily UT).

c) Unmodeled components are evaluated using the same methods as modeled components, with the exception of the lack of a modeled prediction of wear. Fitness for service and remaining service life is evaluated based on measured wear, with a safety factor applied in accordance with EPRI Report 1011838 (NSAC-202L-R3).

## AMP Audit - B.3.10-03

Clarify which quantitative dissolved oxygen concentration criterion is used to establish whether or not a raw water system should be excluded from the scope of the Flow-Accelerated Corrosion Program based on the system's dissolved oxygen content level. Identify what the average dissolved oxygen content concentrations have been in these raw water systems (i.e., service/river water system, circulating water system, and fire protection system) based on past history over the last five years.

## VEGP Response:

Systems with high dissolved oxygen (DO) content were excluded from further evaluation for FAC susceptibility based on engineering judgment using the guidance provided in NSAC-202L. The NSAC-202L guidance indicates that systems with DO levels greater than 1000 ppb can be excluded from further evaluation due to their relatively low level of susceptibility. Dissolved oxygen is not a parameter that is controlled in the River Intake, NSCW, Circulating Water, or Fire Protection Systems, therefore DO is not routinely monitored in these systems and sample results as requested are not available. However, the Chemistry Department estimates that DO levels in these systems would be expected to be in a range of 5000 to 6000 ppb.

## AMP Audit - B.3.10-04

Clarify whether system operating pressure is also used as a energy level parameter for including or excluding system from the scope of the Flow-Accelerated Corrosion Program. If so, identify which system operating pressure exclusion criterion is used for this program.

## VEGP Response:

System operating pressure is not used by itself to determine susceptibility of systems or portions of systems to flow-accelerated corrosion. System operating pressure is used as an input to the determination of whether a system or portion of a system could be excluded from further consideration based on containing a single-phase fluid with operating temperature less than 200F. All lines with operating temperature less than 200F and operating pressure greater than 14.7 psi are identified as containing single-phase fluid.

## AMP Audit - B.3.10-05

Identify what the normal steam quality is for steam flowing through the Vogtle steam outlet nozzles.

## VEGP Response:

The steam generator steam outlet nozzles are exposed to steam with a quality fraction of 99.73 percent or greater.

## AMP Audit - B.3.10-06

The Flow-Accelerated Corrosion Program credits radiography testing (RT, a volumetric examination technique) as a sizing technique for pipe sizes which a tangential view of both walls can be shown on the film. Clarify whether VEGP has qualified RT as a sizing technique in accordance with the VEGP performance demonstration initiative (PDI) or some other NRC-accepted qualification process and if so, identify the type of components and components sizes that the qualification process has qualified RT for as a sizing technique. If RT has not been qualified as a sizing technique under the PDI, justify why it is acceptable to use RT as a sizing technique for flaw indications that are detected in ASME Code Class components.

## VEGP Response:

RT examinations performed for the FAC Program are not used for detection and sizing of flaws, only for measuring wall thickness. Therefore, the RT examinations performed for the FAC Program are not required to be qualified according to any performance demonstration initiative. RT inspections are useful to establish whether or not significant wall thinning exists, especially for geometries where UT examination capabilities are limited (e.g.: socket welded fittings). RT is also beneficial for conducting inspections during plant operation. EPRI NSAC-202L describes the use of RT as a part of an effective FAC Program.

## AMP Audit - B.3.10-07

NRC Information Notice (IN) 2001-09 summarizes relevant information related to a FAC-induced failure of a PWR moisture separator reheater drain line in August of 1999. The affected licensee's root cause analysis of the FAC-induced event highlighted two aspects that may have exacerbated the rate of FAC in the impacted piping component:
(1) presence of a backing bar in the relevant pipe elbow weld configuration resulted in more turbulent flow conditions than were modeled for by CHECWORKS, and
(2) the scope of the UT examinations performed on straight length of piping downstream of the pipe elbow weld did not cover the length of pipe recommended for inspection in EPRI Report NSAC-202L-R2.

In the license renewal basis evaluation document for this AMP, VEGP states that the operating experience in IN 2001-09 was bounded by the VEGP Flow-Accelerated Corrosion Program because: "(1) VEGP performs more FAC inspections that do the licensees for Callaway or Wolf Creek, (2) VEGP historically maintains better water chemistry that is done at Callaway or Wolf Creek, (3) VEGP continually maintains and updates its CHECWORKS code. (4) VEGP was already implementing inspections of counter-bore areas of piping welds, and (5) VEGP does not limit selection of inspection locations to only those predicted by CHECWORKS." Clarify how the VEGP Flow-Accelerated Corrosion Program accounts for and bounds turbulent conditions that could be induced by the presence of backing bars in the piping within the scope of the AMP, especially if backing bars are left in place in the structural weld configurations for valve body, pipe elbow, flow orifice/restrictor, and pipe expander/reducer type piping elements. Clarify whether the VEGP program implements the recommendations in EPRI Report NSAC-202L-R2 that UT examinations of applicable weld locations cover a base metal distance equal to two times the nominal pipe diameter, both upstream and downstream of the weld locations.

## VEGP Response:

The VEGP Flow-Accelerated Corrosion (FAC) Program implements the guidance of NSAC-202L, revision 3, which addressed the operating experience from the 1999 incident at Calloway and the related follow-up inspections that were performed in 2001 and which are discussed in Information Notice 2001-09.

While VEGP typically has not used backing rings in piping with a design pressure of 600 psig or higher, for lower pressure piping the piping specification allows use of backing rings for certain piping material classifications. Weld locations are subject to more detailed inspection, in part because backing rings could exist in some piping. In accordance with the VEGP FAC UT inspection procedure, the entire grid square is scanned for the grid adjacent to each side of each weld, as opposed to scanning just the grid intersection points (NMP-ES-024-510, paragraph 12.2.5). This ensures identification of any accelerated wear occurring near the weld such as might occur from undercutting of a backing ring.

The VEGP program implements the recommendations in EPRI Report NSAC-202L, revision 3, section 4.5.2, regarding grid coverage for piping components. This section recommends that "the inspection grid extend from two grid lines upstream of the toe of the upstream weld to a minimum of two grid lines or 6 inches (150 mm), whichever is greater, beyond the toe of the downstream weld." For expanding components it is further recommended that "The grid should be extended upstream 2 grid lines or six inches (150 mm), whichever is greater."

Grid extensions beyond that are only needed if a degrading trend or significant damage is noted. The "two diameters" figure is provided as a consideration to avoid the potential for having to expand grid

coverage after initial inspection. The SNC procedure, NMP-ES-024-510, paragraph 10.5, specifies grid coverage of 2 grids or 4" upstream to 2 grids or 12" downstream. For expanding components the upstream grid is 2 grids or 12", therefore SNC practices envelope the actual NSAC-202L recommendations.

## AMP Audit - B.3.11-01

The Program Description for the Flux Thimble Tube Inspection Program states that test results are evaluated to determine the wear rate using proprietary methodology. Further, it states that the methodology includes applying an allowance for uncertainty to the measured wear data. The WCAP-12866 methodology includes using a generic wear rate exponent for predicting wear projections in lieu of using actual plant-specific wear rate data. However, NRC Bulletin 88-09 recommends that actual plant-specific wear result data be used establish the actual wear rate projections for a Westinghouse-designed PWR's flux thimble tubes. Clarify whether the generic wear rate equation and exponent in WCAP-12866 will be used to establish the wear rate projections for this AMP or whether the actual wear rate results for the VEGP flux thimble tube examinations will be used to establish the specific wear rate projections for the thimble tubes.

## VEGP Response:

Consistent with NRC Bulletin 88-09, WCAP-12866 recommends the use of a plant-specific wear rate exponent using the inspection results from the previous cycle. According to WCAP-12866, these exponential values are to be determined, "...using subsequent cycle inspection data." However, an allowance is made in the WCAP for plants which do not have subsequent cycle data to use a generic exponential value based on industry results. VEGP uses exponential values based on plant-specific inspection data. VEGP would only select a generic wear rate factor for cases in which a plant specific wear rate factor was either unavailable or considered nonconservative. Lack of plant-specific data could occur such as during the initial period after replacement of a flux thimble tube..

## AMP Audit - B.3.13-01

Please address the following for the "scope of program" program element discussion in LRA AMP B.3.13, "Inservice Inspection Program":

a. Clarify whether the scope of the Reactor Internals Program covers all ASME inspection item requirements in the ASME Code Section XI, Table IWB-2500-1 for Examination Categories B-N-1 and B-N-2.

b. Provide your basis why the "scope of program" program element does not credit ASME Code Section XI, Subsection IWC for remaining ASME Class 2 systems at VEGP (i.e., for those VEGP Class 2 systems that are not part of the VEGP Model F steam generators).

c. Clarify which ASME Section XI Examination Categories and Inspection Items are within the scopes of the ACCW System Carbon Steel Components Program (Appendix B.3.1), Bolting Integrity Program (Appendix B.3.2) Boric Acid Corrosion Control Program (Appendix B.3.3), and External Surfaces Monitoring Program (Appendix B.3.8). Clarify whether the collective scope of these AMPs includes all visual examination-based inspection items in ASME Section XI Table IWC-2500-1 for VEGP Class 2 components and in ASME Section XI Table IWD-2500-1 for VEGP Class 3 components.

## VEGP Response:

The intent of the listing in Section B.3.13 of the VEGP LRA was to identify those areas for which the ISI Program is specifically credited for license renewal as shown in the VEGP License Renewal Application (LRA) Section 3 AMR results tables. Additionally, the intent of the listing in Section B.3.13 of the VEGP LRA was to clarify for the staff those areas where ISI Program inspection activities are credited as a part of an integrated program (e.g. the Bolting Integrity Program) and consequently is not specifically identified in the VEGP LRA Section 3 AMR results tables. These integrated programs are included in the VEGP license renewal application in an effort to align with NUREG-1801 and NRC staff expectations regarding the aging management programs in a license renewal application.

As a further clarification, the VEGP LRA is not proposing any changes to the scope of the VEGP ISI Program. The VEGP LRA relies on continued compliance with the inservice inspection requirements of 10 CFR 50.55a.

The ISI Program scope is broader than the set of inspections explicitly credited for license renewal. SNC will replace the ISI Program scope description in Section B.3.13 of the VEGP LRA with the following:

> "The ISI program scope is defined by ASME Section XI Subsections IWB-1000, IWC-1000, IWD-1000, and IWF-1000 for Class 1, 2, and 3 components and supports, and includes all pressure-retaining components and their integral attachments."

The following responses to items a through c of this audit question B.3.13-1 provide further clarification of the ISI Program activities that are credited in the License Renewal aging management results.

a. The intent of the first bullet shown in the VEGP LRA Section B.3.13 "Program Scope" section was to clarify that all VEGP applicable IWB categories are credited for license

renewal, and that category B-N-3 is credited as part of the Reactor Internals Program. Categories B-N-1 and B-N-2 were inadvertently listed in the first sentence instead of Category B-N-3.

The first bullet should have read: "All VEGP applicable IWB examination categories. Category B-N-3 examinations are credited under the Reactor Internals Program."

The LRA amendment will eliminate this discrepancy.

To further clarify, in this case SNC is not proposing an alternative to ASME Section XI examination requirements for reactor internals. The Reactor Internals Program addresses the possibility of broader inspection requirements for some component locations to detect wear. See the response to audit question B.3.24-1 for additional information.

b. The VEGP LRA does credit ASME Code Section XI, Subsection IWC for other ASME Class 2 systems at VEGP, however it is mainly as part of other programs that utilize ISI Program inspections.

Consistent with NUREG-1801, the VEGP license renewal aging management strategy for managing the internal surfaces of many ASME Class 2 components exposed to fluid environments credits water chemistry controls, along with confirmatory one time inspections in some cases. For the steam generators, the VEGP Section 3 AMR results tables explicitly credit the ISI Program inspections.

In other cases, ISI Program examinations are implicitly credited as a part of an integrated aging management program (e.g. Bolting Integrity Program, ACCW System Carbon Steel Components Program) and the ISI Program is not specifically listed in the VEGP Section 3 AMR results tables. ASME Code Section XI, Subsection IWC examinations credited by other programs are summarized in the third bullet of the ISI Program Scope description in VEGP LRA Section B.3.13.

c. The following aging management programs include credit for specific ISI Program examinations. Also listed are the current ASME Section XI examination categories associated with the credited ISI Program examinations..

<u>ACCW System Carbon Steel Components Program</u>
The ACCW System Carbon Steel Components Program credits VT-2 examinations performed during system pressure tests, which currently includes the following ASME Section XI Examination Categories:
Table IWC-2500-1 Category C-H
Table IWD-2500-1 Category D-B

<u>Bolting Integrity Program</u>
The Bolting Integrity Program is an integrated aging management program that credits ISI Program inspections associated with safety related fasteners. These inspections currently include the following ASME Section XI Examination Categories:
Table IWB-2500-1 Category B-G-1
Table IWB-2500-1 Category B-G-2
Table IWB-2500-1 Category B-P
Table IWC-2500-1 Category C-D

Table IWC-2500-1 Category C-H
Table IWD-2500-1 Category D-B

Boric Acid Corrosion Control Program
Boric Acid Corrosion Control Program (BACCP) partially relies on ISI activities to identify leakage from borated water systems. These activities include VT-2 examinations performed during system pressure tests, which currently includes the following ASME Section XI Examination Categories:
Table IWB-2500-1 Category B-P
Table IWC-2500-1 Category C-H
Table IWD-2500-1 Category D-B

The BACCP also utilizes the ISI Program to implement augmented examinations for RCS nickel alloy locations.

External Surfaces Monitoring Program
The External Surface Monitoring Program is credited to manage externally initiated corrosion. The External Surfaces Monitoring Program was inadvertently included in the list of programs crediting VEGP ISI Program inspections. The LRA amendment will eliminate this discrepancy. While program inspections are capable of detecting corrosion, these exams are not explicitly credited for license renewal. However, some ISI inspection results may be used to fulfill program requirements.

Finally, SNC clarifies that the examination categories listed above do not include all of the visual examination requirements from ASME Section XI Tables IWC-2500-1 and IWD-2500-1 as applicable to VEGP. Table IWD-2500-1 Examination Category D-A is not credited. The External Surface Monitoring Program is credited to manage externally initiated corrosion.

A License Renewal Application amendment is required.

## AMP Audit - B.3.13-02

The LRA includes the following sentence in the "monitoring and trending" program element for AMP B.3.13, "Inservice Inspection Program":

> "Indications that exceed the acceptance standards are extended to include additional examinations in accordance with ASME Section XI."

Please explain the intent of the stated sentence.

## VEGP Response:

The intent of the statement was to highlight the examination scope expansion requirements of ASME Section XI. The VEGP LRA statement should have read:

"Examinations that reveal indications that exceed the acceptance standards are extended to include additional examinations in accordance with ASME Section XI."

A License Renewal Application amendment is required.

## AMP Audit - B.3.13-03

In regard to the AMP B.3.13, "operating experience" program element, clarify whether any VEGP-specific or generic industry experience (including NRC Bulletins 2003-02 and 2004-01 and First Revised Order EA-03-009) has been used to augment the inspection requirements for the Inservice Inspection Program beyond what is currently required pursuant to 10 CFR 50.55a and the ASME Code Section XI, Subarticles IWA, IWB, IWC, IWD, and IWF. If relevant operating experience has been used to augment the Inservice Inspection Program, identify the reference (source) documents (if any) that addressed the experience and clarify whether the source documents have been docketed for VEGP. Identify whether the source documents have included any supplemental regulatory commitments (if any) to the NRC to address such experience and if so, whether these commitments are within the scope of the Inservice Inspection Program.

## VEGP Response:

Regarding ASME Class 1 components at VEGP, the Inservice Inspection (ISI) Program currently implements additional inspection requirements for some ASME Class 1 nickel alloy locations. The VEGP RCS Alloy 600 material inspection program is the current-term program vehicle that identifies and controls the implementation details and commitments for these nickel alloy component locations, including applicable operating experience and NRC commitments (e.g., NRC Bulletins 2003-02 and 2004-01 and First Revised Order EA-03-009). For the period of extended operation, the Nickel Alloy Program for Reactor Vessel Closure Head Penetrations and the Nickel Alloy Program for Non-Reactor Vessel Closure Head Penetration Locations are the program vehicles for the implementing details and commitments. The Nickel Alloy Program for Reactor Vessel Closure Head Penetrations is an existing "subprogram" of the VEGP RCS Alloy 600 material inspection program. SNC expects that the Nickel Alloy Program for Non-Reactor Vessel Closure Head Penetration Locations will also be a "subprogram" of this existing nickel alloy material inspection program. Relevant operating experience for these programs is included under sections B.3.14 and B.3.15 of the application, and related audit questions.

The VEGP ISI Program implemented risk-informed ISI (RI-ISI) for Class 1 and 2 piping during the second inspection interval. Although not considered augmented inspections, the RI-ISI process considers pertinent operating experience in evaluating risk and locations to be inspected. SNC plans to continue using RI-ISI for Class 1 and 2 piping for the subsequent intervals.

The VEGP ISI Program includes augmented examinations for the reactor coolant pump flywheels as required by VEGP Technical Specification 5.5.7.

Regarding ASME Class 2 components at VEGP, the ISI Program currently includes augmented inspection requirements for Main Steam and Feedwater Piping. For each unit, the four main steam lines and feedwater lines from the containment penetration flued head outboard welds up to the first five-way restraint are examined as required by VEGP Technical Specification Section 5.5.16. This augmented 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 in the updated FSAR.

## AMP Audit - B.3.13-04

License renewal basis document VEGP-LR-AMP-15, Version 1 states: "Examinations revealing indications that exceed the acceptance standards are extended to include additional examinations in accordance with ASME Section XI," and indicates that the corrective actions for the Inservice Inspection Program, are initiated in accordance with the applicant's 10 CFR Part 50, Appendix B program. Corrective actions for ASME Code Class 1, 2, and 3 components and their component supports are also mandated in accordance with the applicable requirements of 10 CFR 50.55a and the ASME Code Section XI, Articles IWA-3000, IWB-3000, IWC-3000, IWD-3000, and IWF-3000. Specifically, the Code permits four corrective action options for flaw indications that exceed the applicable flaw acceptance criteria:
(1) acceptance by further inspection, (2) acceptance by supplemental flaw evaluation,
(3) acceptance by repair, or (4) acceptance by replacement.

a. Clarify which ASME Code, Section XI-based options will be used to take further corrective action for those relevant flaw indications that exceed the applicable flaw acceptance standards in IWA-3000, IWB-3000, IWC-3000, IWD-3000, or IWF-3000.

b. Clarify how VEGP's 10 CFR Part 50, Appendix B quality assurance program and process is implemented to ensure that the appropriate corrective actions of the ASME Code Section XI are and will continue to be implemented as part of the Inservice Inspection Program.

## VEGP Response:

In response to part a, SNC clarifies that corrective actions taken in response to indications identified during ISI Program inspections are consistent with the requirements of 10 CFR 50.55a and ASME Section XI Articles IWA-3000, IWB-3000, IWC-3000, IWD-3000, and IWF-3000 and may include acceptance by supplemental examination, by analytical evaluation, or by repair / replacement.

Regarding part b, any unacceptable condition identified during ISI Program activities results in initiation of a condition report and subsequent evaluation of the condition by the corrective actions program. Further, the SNC Quality Assurance Program performs periodic audits of the ISI Program to ensure that the corrective actions are consistent with 10 CFR 50.55a and ASME Section XI requirements.

## AMP Audit - B.3.13-05

License renewal basis document VEGP-LR-AMP-15, Version 1, indicates that VEGP performs augmented inspections of the Chemical Volume and Control System (CVCS) let down piping between the flow orifices and their respective isolation valves in accordance with the VEGP risk-informed ISI (RI-ISI) program. The augmented inspections detected wall thinning in the components and a root cause analysis credited the wall loss to thinning by cavitation. The LRA indicates that AMP B.3.10, Flow-Accelerated Corrosion Program, is also credited for managing wall thinning induced by cavitation. Clarify whether the augmented inspections of this CVCS piping component will be implemented as part of AMP B.3.13, Inservice Inspection Program, or AMP B.3.10, Flow Accelerated Corrosion Program. Clarify what type of augmented inspection techniques will be implemented for this piping component

## VEGP Response:

Inspections of CVCS piping downstream of the CVCS letdown orifices is addressed by the VEGP ISI Program. Ultrasonic examination techniques are used.

## AMP Audit - B.3.13-06

AMP B.3.13, Inservice Inspection Program, provides VEGP's inservice inspection (ISI) aging management program for ASME Code Class 1, 2, and 3 system and components and their component supports. The staff requests the additional clarifications on how the program elements for AMP B.3.13, Inservice Inspection Program, as credited for aging management, compare to the scope of the ASME Code Section XI ISI program that is used for compliance with the ISI requirements of 10 CFR 50.55a:

A. Clarify which VEGP systems and components are within the scope of the ISI program that is credited for compliance with the requirements in 10 CFR 50.55a for ASME Code Class 1, 2, and 3 systems and their components supports, and identify which ASME Code Class and ASME Code Section XI Examination Categories are applicable to these systems and components.

B. Of the systems and components identified in your response to part A of this question, clarify which systems and components are within the scope of the Inservice Inspection Program that is credited for aging management in accordance with the requirements of 10 CFR 54.21(a). For these systems and components, identify which of the ASME Code Section XI Examination Categories that are used for compliance with the requirements of 10 CFR 50.55a are also credited for aging management in accordance with the requirements of 10 CFR 54.21(a) and those that are not, along with a justification for excluding the particular Examination Category from the scope of aging management.

## VEGP Response:

In response to part A:
See the VEGP response to question B.3.13-01, which clarifies that the scope of the VEGP ISI Program is defined by ASME Section XI Subsections IWB-1000, IWC-1000, IWD-1000, and IWF-1000 for Class 1, 2, and 3 components and supports, and includes all pressure-retaining components and their integral attachments. The VEGP ISI Program is a plant-specific program which implements the requirements of 10 CFR 50.55a at VEGP. The VEGP 3rd Ten-Year Interval Inservice Inspection Program document includes a list of applicable VEGP systems and components and a list of ASME Section XI Examination Categories applicable to VEGP Units 1 and 2.

Additionally, Section 2 of the VEGP LRA provides a listing of VEGP systems within the scope of license renewal. Systems in the scope of license renewal which meet the criteria of 54.4(a)(1) include all systems and components that are categorized as ASME Safety Class 1, 2, or 3. All of these systems and components fall under the scope of the VEGP ISI Program as implemented in conformance with 10 CFR 50.55a.

In response to part B:
See the VEGP response to question B.3.13-01, which amends the ISI program scope to clarify the ASME Code Section XI Examination Categories used for compliance with the requirements of 10 CFR 54.21(a). This response identifies the ASME Section XI Examination Categories associated with the VEGP ISI Program but which are credited as a part of integrated aging management programs (e.g. for which the ISI Program is not specifically listed in the VEGP AMR Results Summary Tables). Additionally, Section 3 of the VEGP LRA identifies the systems and components directly crediting ISI Program inspections for aging management in accordance with 10 CFR 54.21(a).

Applicable ASME Section XI Examination Categories credited for aging management consistent with the requirements of 10 CFR 54.21(a) include:

IWB
All IWB Section XI Examination Categories. For the reactor vessel internals, SNC notes that the VEGP Reactor Vessel Internals Program is the inspection program credited in Section 3.1 of the VEGP LRA. However, this program is not intended to replace ASME Section XI inspection requirements for the reactor internals. See the VEGP response to question B.3.13-01 for additional discussion. For steam generator tubing examinations, examinations are effectively implemented by the VEGP Steam Generator Tubing Integrity Program, which is the aging management program shown in Section 3.1 of the VEGP LRA.

IWC
All IWC Section XI Examination Categories applicable to VEGP that are associated with recirculating steam generators. Additionally, see the IWC categories listed in the VEGP response to question B.3.13-01 for a listing of IWC categories credited as a part of integrated aging management programs.

IWD
IWD Section XI Examination Categories credited for aging management include those categories previously listed in the VEGP response to question B.3.13-01. The IWD Section XI Examination Categories credited are included as part of integrated aging management programs.

IWF
All IWF Section XI Examination Categories.

The VEGP aging management reviews were performed by qualified engineers using appropriate industry, vendor, and NRC guidance regarding identification of aging effects requiring management and appropriate aging management techniques. The results of the VEGP aging management reviews are summarized in Section 3 of the LRA. Descriptions of credited aging management programs are provided in Appendix B of the VEGP LRA. Additionally, the aging management programs credited by VEGP are compared to NUREG-180 in Section 3 of the VEGP LRA. Largely, the VEGP approaches toward aging management are consistent with the intent of NUREG-1801. Where, the VEGP approach is different than NUREG-1801, a discussion of the basis for the difference is described in Section 3 of the VEGP LRA. Aging management strategies not contained in, or consistent with, NUREG-1801 are reviewed by the staff on an item-by-item basis.

Finally, as stated in response to question B.3.13-01, SNC clarifies that 10 CFR 50.55a specifies requirements for implementation of ASME Section XI in ISI Programs. Irrespective of the VEGP aging management reviews, the VEGP ISI Program will continue to be implemented in accordance with 10 CFR 50.55a, both in the current term and in the period of extended operation.

## AMP Audit - B.3.15-01

"Nickel-Alloy Management Program for Reactor Vessel Closure Head Penetrations," provides a discussion on relaxations or alternatives that were granted to VEGP relative to the augmented inspection and assessment requirements of NRC First Revised Order EA-03-009. Reliefs or alternative programs granted by the NRC to deviate from applicable requirements in NRC First Revised Order EA-03-009 have only been approved for the current licensed operating period and have not yet been granted relative to the period of extended operation. Clarify what type of commitment will be made on the application to ensure that such relief requests or alternative program requests will be submitted for the 10-Year ISI Intervals or ISI periods in the period of extended operation if such reliefs or alternative programs are desired for the period of extended operation.

## VEGP Response:

NRC First Revised Order EA-03-009 was issued to Southern Nuclear Operating Company's (SNC) Vogtle Electric Generating Plant (VEGP) on February 20, 2004, modifying the VEGP current license. Subsequently, SNC requested and was granted two relaxations from the requirements of the First Revised Order. The requirements of the First Revised Order and the associated relaxations modify the VEGP current license and are part of the VEGP licensing basis. NRC Safety Evaluations (ADAMS Accession Nos. ML052300617 and ML062360585) associated with VEGP relaxations from the requirements of NRC First Revised Order state they are approved "for the time period for which the Order is in effect" and "until the Order is replaced or rescinded." Therefore; for the time period that the First Revised Order remains in effect, the First Revised Order as modified by the relaxations will remain as part of the VEGP licensing basis, and will be carried forward as part of the VEGP renewed license.

Additionally, a footnote associated with 10 CFR 50.55a states:

"Supplemental inservice inspection requirements for reactor vessel pressure heads have been imposed by Order EA-03-09 issued to licensees of pressurized water reactors. The NRC expects to develop revised supplemental inspection requirements, based in part upon a review of the initial implementation of the order, and will determine the need for incorporating the revised inspection requirements into 10 CFR 50.55a by rulemaking."

An ASME Code Case N-729-1 has been developed addressing alternative examination requirements for PWR reactor vessel upper heads with nozzles having pressure-retaining partial penetration welds. In August 2006, the NRC issued a letter to NEI describing its position on the use of ASME Code Case N-729-1 in lieu of First Revised Order EA-03-009. Subsequently, the NRC proposed to amend 10 CFR 50.55a to require the use of ASME Code Case N-729-1 with conditions (Federal Register / Vol. 72, No. 65 / Thursday, April 5, 2007 / RIN 3150-AH76). Presently, the NRC is still receiving comments on this proposed rulemaking.

Based on the above information, it is SNC's understanding the relaxations currently approved for VEGP relative to the First Revised Order remain in effect while the Order remains in effect. The requirements of the First Revised Order and any associated relaxations are not linked to an inservice inspection (ISI) interval or an operating period, but are a part of the VEGP licensing basis and are expected to remain in effect pending long-term resolution of RPV head penetration inspection requirements. Therefore, no comittments will be made in the VEGP license extension application regarding First Revised Order requirements being included as part of the 10-Year ISI Intervals. It is likely based on the ongoing rulemaking activities that the applicable requirements of the order will be codified under 10 CFR 50.55a

and the order rescinded. 10 CFR 50.55a will govern processing of any requests for alternative or requests for relief if this occurs

## AMP Audit - B.3.15-02

The "corrective action" program element in GALL AMP XI.M11-A states:

> " . . . detection of leakage or evidence of cracking in the VHP nozzles (including associated J-groove welds) of plants ranked in the "Low," "Moderate," or "Replaced" susceptibility categories requires that the plant's VHP nozzles be immediately reclassified to the "High" susceptibility category and that the required augmented inspections for "High" susceptibility VHP nozzles be implemented, commencing from the same outage in which the leakage or cracking was detected. Repair and replacement procedures and activities either must comply with ASME Section XI, as invoked by the requirements of 10 CFR 50.55a, or conform with applicable ASME Code Cases that have been endorsed in 10 CFR 50.55a by reference in the latest version of NRC Regulatory Guide 1.147. Alternative repair/replacement activities suggested instead of those endorsed by the NRC in either Section XI or NRC-approved Code Cases must be requested for NRC approval in accordance with either the acceptable alternative provisions of 10 CFR 50.55a(a)(3)(i) or hardship provisions of 10 CFR 50.55a(a)(3)(ii)."

Clarify whether or not VEGP's augmented inspection program for its reactor vessel closure heads and their penetration nozzles, as implemented in accordance with the AMP B.3.15, Nickel Alloy Management Program for Reactor Vessel Closure Head Penetrations (and the requirements of the NRC's First Revised Order EA-03-009), includes these corrective action criteria.

## VEGP Response:

SNC clarifies that if leakage of a reactor vessel head penetration nozzle is detected or if evidence of cracking is detected in a reactor vessel head penetration nozzle, the VEGP reactor vessel head will be reclassified into the "High" susceptibility category as defined by NRC First Revised Order EA-03-009. Additionally, the required augmented inspections for "High" susceptibility reactor vessel head penetration nozzles will be implemented, commencing in the same outage in which the penetration nozzle leakage or cracking was detected. Repair and replacement procedures and activities will comply with the requirements of 10 CFR 50.55a and ASME Section XI.

## AMP Audit - B.3.16-01

AMP B.3.16, Oil Analysis Program, includes the following enhancement on the "parameters monitored/inspected" program element for the AMP:

> 'For the components in the scope of license renewal determination of the viscosity, neutralization number and flash point of lubricating oil samples will be required for components where the oil is changed based on its analyzed condition instead of being changed on a regular schedule regardless of condition."

Clarify whether the intent of this enhancement is to invoke viscosity testing, neutralization number testing, and flash point testing for both oil that is replaced or replenished on a periodic basis and does not get replaced or replenished on a periodic basis or whether the intent of the enhancement is to invoke viscosity testing, neutralization number testing, and flash point testing only for oil that is replaced or replenished on a periodic basis. If the later intent is meant, provide your basis for not crediting these tests for lubricating oil that does not get replaced or replenished on a regular basis.

## VEGP Response:

Lubricating oil at VEGP presently falls into one of two categories:
1) Oil that is replaced based on its analyzed condition;
2) Oil that is replaced on a regular schedule regardless of condition.

Oil that is replaced on a regular schedule will continue to be replaced on that schedule during the period of extended operation in accordance with the current requirements of the Oil Analysis Program (with the stipulation that the SNC fleet-wide Oil Analysis Program currently in development could make changes determined by identification of best practices).

For oil that is changed based on its analyzed condition, the Oil Analysis Program is being enhanced to require viscosity testing, relative level of oxidation testing, and flash point testing, which may or may not be presently performed for the various affected components included in the program.

The relative level of oxidation of the lubricating oil will be monitored by analysis of the neutralization number (also known as acid number or base number per the current version of ASTM D974) or other appropriate parameter(s), such as conductivity, which measure changes in the relative level of oxidation of the lubricating oil.

The evaluation of this element included an enhancement that the flash point would be determined for lubricating oil samples where the oil is changed based on analyzed condition instead of at regular intervals. SNC would like to clarify this enhancement in that the flash point of lubricating oil will be monitored for those components where the oil is changed based on analyzed condition instead of at regular intervals, and which have the potential for contamination of the lubricating oil with a light hydrocarbon such as fuel oil. Flash point monitoring can provide useful information regarding the condition of lubricating oil which could be diluted by a light hydrocarbon. For components where there is no potential for contamination of the lubricating oil with a light hydrocarbon, other analyses provide direct monitoring of the parameters relevant to the condition of the oil. In these cases flash point monitoring is superfluous.

A License Renewal Application amendment is required to document this clarification.

## AMP Audit - B.3.16-02

AMP B.3.16, Oil Analysis Program, includes the following enhancement on the "parameters monitored/inspected" program element for the AMP:

> 'Analytical ferrography or elemental analysis to identify wear particles or corrosion products when a lubricating oil sample's particle count exceeds established limits or action levels will be required for the components in the scope of license renewal."

Provide your basis why the implementation of ferrography and elemental analysis will be implemented only if of the particulate counts from the particulate testing exceeds the acceptance criteria limits for particulate count.

## VEGP Response:

VEGP currently screens all lubricating oil samples for kinematic viscosity, water content and wear metal content. This applies both to components with periodic lubricating oil changes and to components where the lubricating oil is changed based on analyzed condition.

The wear metal content screening provides a relative measure of the change in the amount of ferrous wear products in the lubricating oil sample versus a baseline sample. The ferrous wear index measures the concentration and size of ferrous particles greater than five microns in size. The value is reported as a non-dimensional value (no units of measurement). Comparison of subsequent lubricating oil sample results to the baseline sample provides the ability to trend changes in the concentration of ferrous wear products in the lubricating oil.

Elemental analysis and neutralization number testing are also performed for certain components in the scope of license renewal where the lubricating oil is changed based on analyzed condition instead of at regular intervals. Components selected for these analyses are selected based on EPRI guidelines, manufacturer's recommended testing and radiological shipping requirements.

For both components with periodic lubricating oil changes and components where the lubricating oil is changed based on analyzed condition, if a lubricating oil sample exceeds the limits established for the wear metal content screening, the lubricating oil from that component will be subjected to additional testing. The additional testing may include detailed particle counting, elemental analysis, or analytical ferrography as necessary to validate the initial screening results and to diagnose the source of the particulates.

The wear metal content screening process described above constitutes an exception to GALL in that the screening does not provide a particle count as described in ISO 4406. VEGP's experience with this wear metal content screening process indicates that the process is very sensitive to the presence of particulate contaminants and therefore is a reliable method to monitor and trend particulate contamination. A License Renewal Application amendment is required to document this exception.

Phosphate ester hydraulic fluid is tested in accordance with manufacturer's recommendations. This fluid is sampled for viscosity, acidity (neutralization number), particle count and water content. For phosphate ester hydraulic fluids, elemental analysis and analytical ferrography are not components of the manufacturer's recommended testing and therefore are not routinely performed. Elemental analysis and analytical ferrography may be performed if deemed necessary to assist in diagnosing potential problems indicated by the manufacturer's recommended testing.

## AMP Audit - B.3.18-01

Under the Detection of Aging Effects program element, GALL AMP B.3.18, "One-Time Inspection Program for ASME Class 1 Small Bore Piping," recommends that for ASME Code Class 1 small-bore piping, one-time inspections using volumetric examination be performed on selected weld locations to detect cracking. The VEGP program will not specifically perform volumetric examinations of the socket welds, but instead credits periodic VT-2 visual examinations of the ASME Code 1 piping socket welds under the VEGP ISI Program. Provide your basis as to how a VT-2 visual examination, in of itself, can assure the integrity of the small bore ASME Class 1 socket welds in lieu of conforming to the GALL Report recommendation. Include in your discussion, your basis why the surface examination requirements for small bore socket welds in ASME Section XI Examination Categories B-F and B-J should not credited in addition to the VT-2 visual examinations required under Examination Category B-P.

## VEGP Response:

The issue of volumetric examination of ASME Class 1 socket welds was recently resolved and included in the NRC's summary dated March 6, 2007 of the License Renewal telephone conference call and meeting between the NRC staff and the License Renewal Task Force held on February 21, 2007 (ADAMS Accession No. ML070580498). The conclusions documented in this summary letter state that industry experience has shown that failures of socket welds are generally internally initiated and surface examinations are not effective in detecting cracks until they are through wall. As a result, the staff concluded that no additional examinations will be required for socket welds in addition to the current ASME code requirements for license renewal. This position has been adopted by the industry for socket welds.

From a practical perspective, there is not an industry demonstrated means of performing volumetric examinations to detect cracking initiating at the inside diameter of a socket weld. Regarding surface examinations, these exams will not reveal cracking initiating from the inside diameter until the crack propagates thru-wall. A VT-2 examination will detect boron residue or leakage from cracks that have occurred in the socket welds. VEGP performs VT-2 examinations for all ASME Class 1 piping locations consistent with the requirements of ASME Section XI, Category B-P. Additionally, VEGP uses a risk informed ISI program in lieu of the ASME Section XI examinations requried for Categories B-F and B-J. The risk informed process considers the possibility of outside diameter initiated cracking as a result of surface contamination (e.g. Chlorides). If determined to be appropriate based on the risk informed ISI review, surface examinations of socket welds would be performed.

These fundamental principles are not altered in the period of extended operation and therefore a conclusion that VT-2 examination is acceptable to manage degradation of socket welded connections remains valid for the period of extended operation.

Finally, VEGP has not had any operating history associated with age related degradation of small bore ASME Class 1 piping. It is noted that VEGP LRA Section B.3.18 describes cracking events associated with RHR bypass piping. These events were determined to be associated with unexpected acoustic loading resulting from inadequate design. There was no evidence of long term, age related degradation associated with these failures.

## AMP Audit - B.3.18-02

Under the Monitoring and Trending program element, GALL AMP B.3.18, "One-Time Inspection Program for ASME Class 1 Small Bore Piping," recommends that the number of inspection locations, or sample size, be based on susceptibility, inspectability, dose considerations, operating experience, and limiting locations of the total population of ASME Code Class 1 small-bore piping locations. However, LRA Section B.3.18 states that the examination locations will be selected using a risk-based approach that will consider the susceptibility, inspectability, dose, and operating experience. Explain how risk is to be used in selecting the examination locations and how a representative sample size for aging management is to be established.

## VEGP Response:

Risk is incorporated into the selection of examination locations in that the VEGP One-Time Inspection Program for ASME Class 1 Piping required for license renewal is implemented at VEGP using the framework of the VEGP Risk-Informed ISI (RI-ISI) Program. Under the RI-ISI program, ASME Class 1 piping was broken out into segments based on size of the piping and the consequence of failure. Failure probabilities were calculated for each segment considering failure mechanisms such as thermal stratification and mixing, vibration, stress corrosion cracking, mechanical loading, thermal loading, and transient loading. Consequence of failure and failure probabilities were then integrated to determine the highly safety significant (HSS) segments to be examined. By definition, these piping segments carry a higher risk of failure and a higher risk of significant consequences if failure occurs. Operating experience at Vogtle and other operating nuclear plants was factored into the evaluation through the use of an expert panel. A statistical model was used to select the minimum number of locations to be examined within each HSS segment to ensure that an acceptable level of piping reliability will be maintained. For each piping segment, the results of the statistical model must show that the number of weld locations selected for inspection results in a confidence level equal to or greater than 95% that current safety margins and the integrity of the piping segment will be maintained.

The RI-ISI Program is re-evaluated periodically. Therefore, the program is periodically updated to address any emerging degradation issues. As a result, the risk-based approach is appropriate not only for the current term, but for the period of extended operation as well.

## AMP Audit - B.3.19-01

One-Time Inspection Program for Selective Leaching Program element 4.3-2 of the one-time inspection program for selective leaching states that follow-up of unacceptable inspection findings includes expansion of the inspection sample size and location. Vogtle claims consistency with this program element even though there is no mention of sample selection size expansion upon the discovery of a unacceptable inspection findings. Explain if the action to adjust sample size is intended within the VEGP Program.
VEGP-LR-AMP-29-1

## VEGP Response:

Section 4.0 of the One-Time Inspection Program for Selective Leaching License Renewal Evaluation Document states "If degradation due to selective leaching is identified, additional examinations will be performed." SNC will revise Section 4.3 (Element 4.3-2) of the One-Time Inspection Program for Selective Leaching License Renewal Evaluation Document to be consistent with Section 4.0 and also with Section B.3.19 of the VEGP LRA.

## AMP Audit - B.3.20-01

LRA Section B.3.20, Overhead and Refueling Crane Inspection Program, states that the program is an existing program that is consistent with GALL AMP XI.M23. The applicant also states in the VEGP basis document for AMP B.3.20 that the program is consistent with GALL AMP XI.M23. The program basis document under program element "Detection of Aging Effects" states that for the cranes within the scope of license renewal, crane rails and crane structural components are routinely visually inspected for excessive wear, corrosion, or misalignment. However, a review of the existing program implementation (inspection) procedures for the Polar Cranes, Refueling Machines (Bridge and Trolley System) and Fuel Handling Machine Bridge Cranes shows that the Polar Cranes are not inspected for corrosion and crane rail wear, the Refueling Machines are not inspected for corrosion and the Fuel Handling Bridge Cranes structural components are not shown as being inspected. Explain how the existing VEGP AMP B.3.20, Overhead and Refueling Crane Inspection Program is consistent with GALL AMP XI.M23 when the existing program does not address the above inspections.

## VEGP Response:

The cranes within the scope of the Overhead and Refueling Crane Inspection Program are routinely inspected, however the existing procedures do not explicitly identify inspection of structural components for excessive wear, corrosion, and misalignment in all cases. The following summarizes the inspections currently performed for structural component corrosion, and for crane rail wear and misalignment.

| | Loss of material due to Corrosion | Loss of material due to Wear (Crane Rails) | Misalignment (Crane Rails) |
|---|---|---|---|
| Polar Crane (procedure 93246-C): | | | |
| Bridge (Girder) | Not specified | N/A | N/A |
| Rails | Not specified | Not specified | Not specified |
| Spent Fuel Cask Crane (procedure 27315-C): | | | |
| Bridge (Girder) | Proc. 27315-C (para. 4.3.2.1) | N/A | N/A |
| Rails | Not specified | Proc. 27315-C (para. 4.1.5.5) | Proc. 27315-C (para. 4.1.5.5, 4.3.9.1) |
| Refueling Machine (procedure 27340-C): | | | |
| Bridge (Girder) | Not specified | N/A | N/A |
| Rails | Not specified | 27340-C (para. 4.1.1, 4.2.1) | Not specified |
| Fuel Handling Machine Bridge Crane (procedure 27342-C) | | | |
| Bridge (Girder) | Not specified | N/A | N/A |
| Rails | Not specified | Not specified | Not specified |

As a result, SNC will enhance applicable plant procedures to explicitly identify inspection of crane rails and crane structural components for loss of material due to corrosion and wear, and for indication of rail misalignment.

The SNC program basis document (VEGP-LR-AMP-30 "Overhead and Refueling Crane Inspection Program License Renewal Evaluation Document" ) will be updated to incorporate this enhancement (program element 4.4-1), and to clarify that SNC includes loss of material due to crane rail wear as an aging effect to be managed under this program (program element 4.1-1).

A license renewal amendment is required to include this enhancement to the Overhead and Refueling Crane Inspection Program to make it consistent with GALL AMP XI.M23. The future action commitment list will also be updated to include this enhancement commitment.

## AMP Audit - B.3.23-02

The first exception in LRA AMP B.3.23, "Reactor Vessel Closure Head Stud Program," for program elements 3, 4, 5, and 6 also states that volumetric examinations are in compliance with the performance demonstration initiative (PDI). Also, this initiative program is currently based on Appendix VIII, 2001 Edition of Section XI as mandated by10 CFR 50.55a. The applicant considers this as an exception to the GALL AMP XI.M3, "Reactor Head Closure Studs," recommendations. However, the staff notes that GALL AMP XI.M3, recommends volumetric examination in accordance with the general requirements of Subsection IWA-2000 and does not mention compliance with the PDI criteria of 10 CFR 50.55a. Please clarify whether your PDI program activities for volumetric examinations are exceptions to the criteria in GALL AMP XI.M3, "Reactor Vessel Closure Studs," or go beyond the recommendations of GALL AMP XI.M3. Discuss how your PDI activities for the volumetric examinations of the closure studs are considered to be adequate to ensure that the volumetric examinations will be capable of detecting the aging effects that are applicable to the studs for the period of extended operation.

## VEGP Response:

ASME Section XI, Mandatory Appendix VIII addressed performance demonstration for ultrasonic examination systems. The performance demonstration requirements implemented in Appendix VIII to ASME Section XI include requirements for examination procedures, personnel qualification, and examination qualification testing. This approach provides a high level of assurance that the combination of equipment, personnel, and procedure is capable of detecting flaws during volumetric examinations. The techniques described in Appendix VIII to ASME Section XI were developed using a consensus process and have been approved for use by the staff via 10 CFR 50.55a. Examinations qualified to meet Appendix VIII requirements provide a higher level of assurance that flaws will be detected and accurately sized when compared with previously used volumetric examination requirements.

Regarding implementation of Appendix VIII, 10 CFR 50.55a (g)(6)(C) states:

"Implementation of Appendix VIII to Section XI. (1) Appendix VIII and the supplements to Appendix VIII to Section XI, Division 1, 1995 Edition with the 1996 Addenda of the ASME Boiler and Pressure Vessel Code must be implemented in accordance with the following schedule: Appendix VIII and Supplements 1, 2, 3, and 8--May 22, 2000; Supplements 4 and 6--November 22, 2000; Supplement 11--November 22, 2001; and Supplements 5, 7, and 10--November 22, 2002."

And, 10 CFR 50.55a (b)(1)(xxiv) states:

"Incorporation of the Performance Demonstration Initiative and Addition of Ultrasonic Examination Criteria. The use of Appendix VIII and the supplements to Appendix VIII and Article I-3000 of Section XI of the ASME BPV Code, 2002 Addenda through the latest edition and addenda incorporated by reference in paragraph (b)(2) of this section, is prohibited."

Appendix VIII, Supplement 8 provides qualification standards for bolts and studs. Therefore, SNC was required by 10 CFR 50.55a (g)(6)(C) to implement PDI requirements for examination of reactor vessel closure head studs no later than May 22, 2000. Additionally, SNC is currently prohibited by 10 CFR 50.55a (b)(1)(xxiv) from using Appendix VIII and the supplements to Appendix VIII from the 2002 Boiler & Pressure Vessel Code, or any later edition and addenda incorporated into 50.55a.

As a result, this exception is intended to clarify that examinations of reactor vessel closure head studs will comply with ISI Program requirements as implemented consistent with 10 CFR 50.55a and not any specific ASME Section XI Code edition and addenda cited in NUREG-1801, Section XI.M3.

## AMP Audit - B.3.23-03

The second exception in LRA AMP B.3.23, "Reactor Vessel Closure Head Stud Program," for program element "detection of aging effects" states that VEGP 3rd Inservice Inspection will be based on ASME Section XI, 2001 Edition including the 2002 and 2003 addenda. Since this edition of ASME Code will not require surface examination, VEGP will not include surface examination in this program.

The GALL AMP XI.M3, "Reactor Head Closure Studs," program element "detection of aging effects," states the program uses visual, surface, and volumetric examinations in accordance with the general requirements of Subsection IWA-2000. The GALL AMP XI.M3 also states that the program uses magnetic particle, liquid penetration, or eddy current surface examination to indicate the presence of surface discontinuities and flaws. In Regulatory Guide (RG) 1.65, Material and Inspections for Reactor Vessel Closure Studs, Paragraph C.4, the staff recommends that the requirements of Section XI of the ASME Code should be supplemented to include a surface examination in accordance with paragraph NB-2545 or NB-2546 of Section III of the ASME Code.

Please provide your technical justification for excluding of surface examinations from the scope of this program, or enhance the VEGP program to include surface examinations as recommended by the GALL AMP XI.M3.

## VEGP Response:

VEGP FSAR Section 1.9.65.2 describes the VEGP position regarding conformance with NRC Regulatory Guide 1.65. VEGP FSAR Section 1.9.65.2, item 3 states:

"Inservice inspection of the bolting will be performed using the following guidelines.

a. All surface examinations will be performed in accordance with ASME Section XI in lieu of paragraph NB-2545 or NB-2546 of ASME Section III.

b. Washers will be examined using the visual techniques as required by ASME Section XI in lieu of the surface examination in Section C.4."

From a practical perspective, volumetric examination techniques, especially those in conformance with Appendix VIII to ASME Section XI (see VEGP response to audit question B.3.23-02), are much improved over the volumetric techniques available at the time Regulatory Guide 1.65 was issued (October 1973). Currently, surface examination in addition to volumetric examination does not provide a significant improvement in assurance of the level of quality and safety. This conclusion is shared by both the ASME Code Committees approving ASME Section XI and by the NRC staff via 50.55a.

SNC maintains that examination in conformance to ASME Section XI as implemented in 10 CFR 50.55a provides an acceptable method for detection of degradation in the reactor vessel closure head stud assemblies.

# Vogtle License Renewal Audit Questions and Answers

## AMP Audit - B.3.23-04

The operating experience section of the VEGP LRA Section B.3.23, "Reactor Vessel closure Head Stud Program," states that review of recent VEGP records identified pitting of the nuts and washers for three Unit 2 closure stud assemblies. The staff noted that, neither LRA AMR tables, nor GALL Volume 2 tables, includes managing loss of material due to pitting corrosion for closure head stud assemblies in the scope of this program. Please clarify whether, or not, loss of material due to pitting is included in the VEGP Reactor Vessel closure Head Stud Program.

## VEGP Response:

An AMR line item to address corrosion of the VEGP RPV closure head studs was inadvertently omitted from Table 3.1.2-1 . An item "6d" will be added to VEGP LRA Table 3.1.2-1 to address corrosion of Closure Studs, Nuts, and Washers. The Reactor Vessel Closure Head Stud Program is credited to manage corrosion of the Closure Studs, Nuts, and Washers.

During the 2002 refueling outage, minor pitting was detected on six Unit 2 reactor vessel stud nuts and washers by visual examination. Fasteners were cleaned, lubricated, and returned to service. These fasteners were re-inspected during the 2004 Unit 2 refueling outage, with no significant progression of the degradation noted. However, three of the nut and washer combinations were judged not to meet the required 70% spherical contact criteria. These nuts and washers were replaced.

A License Renewal Application amendment is required.

## AMP Audit - B.3.24-01

Reactor Vessel Internals Program, provides the following statement relative to aging management discussions in relevant aging management review (AMR) items of NUREG-1801, Revision 1, Section IV.B2:

> "The VEGP Reactor Vessel Internals Program will manage wear of reactor vessel internals components. NUREG-1801, Section IV.B2, credits Inservice Inspection Program visual inspections to manage wear of the reactor vessel internals. Reactor vessel internals inspection and evaluation guidance currently in development by the EPRI MRP Reactor Internals Focus Group will consider the potential for wear of reactor vessel internals components. The resulting inspection requirements may or may not align with existing ASME Section XI inspection requirements."

Pursuant to the requirements of 10 CFR 50.55a(a)(3), relief must be requested if Southern Nuclear is considering the EPRI MRP Internals Focus Group activities as an alternative to the required Inspection Items in the ASME Code Section XI, Table IWB-2500-1, Examination Categories B-N-1 and B-N-2. Clarify what type of regulatory commitment will be made on the application (if any) to ensure that appropriate relief requests will be submitted for the 5$^{th}$ and 6$^{th}$ 10-Year ISI intervals in the period of extended if the EPRI MRP Internals Focus Group activities do not include inspection activities for the Inspection Items in ASME Code Section XI, Table IWB-2500-1, Examination Categories B-N-1 and B-N-2.

## VEGP Response:

The SNC Reactor Vessel Internals Program is not proposing alternatives to ASME Section XI examination requirements. The ISI Program described in AMP B.3.13 governs implementation of ASME Section XI examination requirements, including any relief requests. As stated in AMP B.3.13, the ISI Program is implemented in accordance with the requirements of 10 CFR 50.55(a). SNC understands that alternatives require the approval of the NRC under the provisions of 10 CFR 50.55a(a)(3) before incorporation into the ISI Program.

Wear of most reactor internals components is expected to be adequately managed by ISI Program inspections. However, the possibility exists that EPRI inspection and evaluation guidelines for PWR reactor internals will conclude that, for some internals locations, augmented inspections in addition to the current ASME Section XI examination requirements are needed. These augmented inspections would be in addition to ASME Section XI requirements. The EPRI Reactor Internals Focus Group is currently in the process of developing these inspection and evaluation guidelines.

In summary, SNC is not proposing alternatives to ASME Section XI examination requirements for reactor internals under the Reactor Vessel Internals Program. Rather, SNC is addressing the possibility of additional inspection requirements for some component locations. The VEGP reactor vessel internals inspection plan will identify the inspection requirements for the reactor vessel internals components. The inspection plan will rely on ISI Program inspections and identify any additional/augmented inspections to be performed.

## AMP Audit - B.3.24-02

Reactor Vessel Internals Program, provides the following statement relative to aging management discussions in relevant aging management review (AMR) items of NUREG-1801, Revision 1, Section IV.B2:

> The Reactor Vessel Internals Program will manage wear of the reactor vessel closure head thermal sleeves. NUREG-1801, Sections IV.A2 and IV.B2, do not address reactor vessel head thermal sleeves.

In addition, the "operating experience" program attribute for the Reactor Vessel Internals Program includes an operating experience summary for the wear-based degradation that occurred in the reactor vessel closure head (RVCH) penetration thermal sleeves.

Clarify what type of examination method or methods were used to detect the wear that occurred in the degraded thermal sleeves. Provide your basis why the examination method or methods that detected the wear in these components are not credited (on a periodic basis) to manage wear in these components for the period of extended operation.

## VEGP Response:

Vessel head thermal sleeve wear indications were initially identified during the performance of examinations of the reactor vessel head to satisfy the requirements of NRC First Revised Order EA-03-009. This inspection involves the insertion of a blade probe into the annulus region between the thermal sleeve and the penetration tube, with the active element facing the penetration tube. Wear was detected in an incidental manner by inspection personnel during insertion of the probe.

Subsequent to this initial, incidental, indication of vessel head thermal sleeve wear, visual examination, including photography for some locations, was used to inspect all of the VEGP vessel head thermal sleeves in the area near the exit of the penetration tubes.

As described in VEGP LRA Appendix B.3.24, the remaining Unit 2 thermal sleeves will be re-inspected at the next scheduled refueling outage, at which time assessments will be performed to identify additional monitoring requirements and corrective actions. This action is appropriate considering the emerging and unexpected nature of this degradation issue. Westinghouse notes that in the vessel head inspections performed at 30 other plants, thermal sleeve wear such as found at VEGP Unit 2 has not been observed. Additionally, a search of INPO and NRC operating experience reports did not identify any observations of vessel head thermal sleeve wear.

Therefore, SNC considers this issue to be an evolving, current term degradation issue for which a firm basis for future inspection plans cannot be established until additional inspection data is obtained and evaluated. As such, establishment of a periodic inspection plan is premature at this time.

Finally, the Reactor Vessel Internals Program description in Section B.3.24 includes a commitment to address wear of the reactor vessel head thermal sleeves. Upon implementation, the Reactor Vessel Internals Program will include an appropriate inspection plan for the vessel head thermal sleeves.

## AMP Audit - B.3.24-03

Reactor Vessel Internals Program, provides the following operating experience summary for the control rod guide tube support pins:

> Earlier in plant life, VEGP preemptively replaced the original Unit 1 and Unit 2 Alloy X-750 Control Rod Guide Tube Support Pins with strain hardened Type 316 stainless steel support pins based on industry experience with PWSCC in Alloy X-750 support pins.

Clarify whether there has been any generic industry experience or VEGP-specific experience relative to loss of material or cracking in control rod guide tube supports pins made from strain hardened Type 316 stainless steel.

## VEGP Response:

The EPRI Materials Handbook for Nuclear Plant Pressure Boundary Applications (MRP-150) indicates that through August 2004, cracking has not been observed in strain hardened Type 316 materials used in domestic plants. Further, MRP-150 notes that slow strain rate test results indicate cold worked Type 316 is resistant to SCC in PWR reactor coolant environments for normal hydrogen concentrations and low neutron fluences.

EPRI Report MRP-191 documents the results of a 2006 screening, categorization, and ranking of reactor internals components for Westinghouse units. This report concludes that SCC of strain hardened Type 316 control rod guide tube support pins is not considered likely.

Loss of material due to corrosion has not been an issue of concern for any stainless steel PWR reactor internals component due to the highly reducing nature of the PWR coolant environment.

Wear is highly location dependent and has not been observed to date for strain hardened Type 316 control rod guide tube support pins.

Additionally, SNC performed a review of recent industry operating experience and was unable to identify any instance of failure or degradation of a strain hardened Type 316 control rod guide tube support pin. Strain hardened Type 316 is the current material of choice for replacement of X-750 control rod guide tube support pins.

## AMP Audit - B.3.24-04

Question # B.3.24-4: The program description discussion for AMP B.3.24, Reactor Vessel Internals Program, as given in VEGP Document #VEGP-LR-AMP-33, Version 1, "Reactor Vessel Internals Program, LR Evaluation Document," provides the following statement:

> "The Reactor Vessel Internals Program includes two component locations that are not currently included in the program under the development by the EPRI MRP RI FG. These locations are the reactor vessel thermal sleeves and the core support lugs, attachment welds, and support pads. For these component locations, SNC will develop appropriate inspection guidance and acceptance criteria based on industry data, VEGP and industry experience, and vendor evaluations / recommendations. Since VEGP is committed to submitting a program to the NRC for review and approval, the staff will have the opportunity to evaluate the VEGP program plan for these two locations in that submittal process."

The commitment to submit an inspection plan for the VEGP reactor vessel (RV) internals for NRC review and approval is given in Part (3) of LRA Commitment No. 20, which was placed onto the dockets for VEGP Units 1 and 2 in SNC Letter NL-07-1261, dated June 27, 2007. Commitment No. 20 does not specifically state that the inspection plan for the VEGP RV internals will include SNC's inspection bases, methods, and criteria for inspecting the RV thermal sleeves and the core support lugs, attachment welds, and support pads. The staff requests that Part (3) of Commitment No. 20 be supplemented to state that the inspection plan will include SNC's bases, methods, and criteria for inspecting the RV thermal sleeves and the core support lugs, attachment welds, and support pads during the period of extended operation.

## VEGP Response:

SNC will amend VEGP License Renewal future action commitment list item no. 20 to add the following text to item (3) of the commitment:

This inspection plan will address the bases, inspection methods, and acceptance criteria associated with aging management of the reactor vessel thermal sleeves and the core support lugs (along with the associated support pads and attachment welds).

## AMP Audit - B.3.26-01

In the "operating experience" program element for AMP B.3.26, "Steam Generator Tubing Integrity Program, under operating experience section, the applicant stated that active degradation mechanism identified in VEGP unit 1 steam generators (SG) during spring 2005 refueling related to PWSCC and ODSCC. The applicant added that as a result, a number of tubes have been plugged and stabilized. However, no active degradation mechanisms have been identified in the VEGP Unit 2 and no SG tubes were plugged during the spring 2007 refueling outage.

a. Clarify how many tubes in the current SG model for each unit have been repaired, stabilized or plugged to date. Identify any additional age-related degradation mechanisms that have induced aging effects in the VEGP Unit 1 SG tubes (if at all) and clarify which type of NDE detection methods (including NDE probe used) were used to detect the relevant aging mechanisms (including PWSCC and ODSCC).

b. Provide your explanation on why VEGP Unit 1 steam generator components had degraded and why the Unit 2 steam generator components did not. Provide your basis whether or not the degradation mechanisms that occurred in the Unit 1 steam generator components could potentially occur in the Unit 2 steam generator components during the period of extended operation and if so, whether they need to be managed.

## VEGP Response:

Item a

The Unit 1 tubes which have been repaired, stabilized, or plugged to date are provided in the following table.

| Unit 1 SG | Tubes Plugged | Tubes Stabilized | Tubes Repaired * |
|---|---|---|---|
| SG 1 | 9 | 3 | 9 |
| SG 2 | 14 | 6 | 14 |
| SG 3 | 25 | 3 | 25 |
| SG 4 | 26 | 11 | 26 |

* Since the repair of tubes at VEGP unit 1 involves only plugging and stabilization, the repaired tubes are the same as those plugged, some which were also stabilized.

The additional age-related degradation mechanisms that have induced aging effects in the VEGP Unit 1 are wear at tubing intersections with anti-vibration bars (i.e. AVB wear), wear due to secondary-side foreign objects, wear at the flow distribution baffle (FDB) plate due to pressure pulse cleaning (PPC), and possible wall loss from ultrasound energy cleaning (UEC) cavitation. Though the AVB wear, foreign object wear, and wear at the FDB degradation mechanisms are frequently in VEGP Unit 1 outages, they have not been detected to an extent meeting the threshold for the industry criteria for active damage mechanism. The possible wall loss due to UEC cavitation was first detected in the 1R13 outage.

The Unit 2 tubes which have been repaired, stabilized, or plugged to date are provided in the following table.

| Unit 2 SG | Tubes Plugged | Tubes Stabilized | Tubes Repaired * |
|---|---|---|---|
| SG 1 | 5 | 1 | 5 |
| SG 2 | 12 | 2 | 12 |
| SG 3 | 4 | 3 | 4 |
| SG 4 | 21 | 2 | 21 |

* Since the repair of tubes at VEGP Unit 2 involves only plugging and stabilization, the repaired tubes are the same as those plugged, some which were also stabilized.

The NDE detection methods used to detect Unit 1 age-related degradation mechanisms are:

1. PWSCC - Eddy current examinations using rotating probe coil (RPC), Ghent probe, and Delta probe,
2. ODSCC - Eddy current examinations using rotating probe coil (RPC), Ghent probe, and Delta probe,
3. AVB wear - Eddy current examinations using bobbin probe,
4. Foreign object wear - Eddy current examinations using bobbin probe and, initiating in 1R8 outage (March 1999), rotating probe coil (RPC)
5. Wear at FDB due to PPC - Eddy current examinations using bobbin probe.
6. UEC cavitation - Eddy current examinations using bobbin probe and rotating probe coil.

Item b

It cannot be specified at this time why Unit 1 steam generator components had degraded and the Unit 2 steam generator components had not. A team has been appointed to review for the root cause of the Unit 1 ODSCC and has not concluded the review. It should be noted that pulling a tube sample will be essential to project the contributing factors in the ODSCC. A tube pull is planned for the 1R14 outage (March 2008).

The Unit 2 eddy current inspection plans are developed with specific focus for detecting degradation mechanisms similar to that detected for Unit 1, for both the PWSCC and ODSCC degradation mechanisms. Current inspection strategic plans provide for these proactive Unit 2 inspections to continue.

## AMP Audit - B.3.26-02

In the "operating experience" program element for AMP B.3.26, "Steam Generator Tubing Integrity Program, the applicant states that wear due to interaction with loose parts or foreign objects have been identified for VEGP. Please discuss how loose or foreign objects are detected and controlled under the Steam Generator Integrity Program.

## VEGP Response:

The following paragraphs describe inspections and maintenance at VEGP which detect and control foreign objects in the steam generators.

Eddy Current
Steam generator (SG) Eddy current inspections performed in the primary side of the tubing detect the presence of foreign objects on the secondary side of the tubing. The industry has established standard three-letter codes to convey information regarding indications. One of the three-letter codes used to designate eddy current signals characteristic of potential loose parts on the secondary side is "PLP". The SNC SG eddy current program methods provide for disposition of PLP indications. This is consistent with industry requirements that potential foreign objects identified during an eddy current inspection be dispositioned. Options for dispositioning foreign object indications include secondary side visual inspection at the location in question, eddy current analytical techniques, and engineering evaluation. Eddy current inspections performed are comprised of a combination of bobbin and rotating probe coil inspections. The frequency of the inspections for each of the VEGP SGs is in accordance with technical specifications and industry requirements. Eddy current inspections also detect the presence of foreign objects indirectly by detecting volumetric wear that can potentially be caused by them. The extent of the response to the wear signals depends on the nature of the wear signals; follow-up actions to control foreign objects may be specified in response to volumetric wear indications.

FOSAR
During most outages, SG secondary side foreign object search and retrieval (FOSAR) is performed for the purpose of identifying any foreign objects, and then removal of any identified objects. If the objects cannot be retrieved, then engineering evaluation is required to demonstrate that tube integrity will be assured during the next inspection interval's power operation until the next opportunity for inspection.

Sludge lance cleaning
During most outages, SG secondary side sludge lance cleaning is performed at the top-of-the-tubesheet. The sludge lancing process removes/washes sludge and scale from the top-of-tubesheet region (TTS), but also washes foreign objects out of the tube bundle, for removal by suction hoses or later via FOSAR.

Summary
In summary, detection and control of foreign objects in the secondary side of the VEGP SGs is achieved through diverse means. Inspections during outages for loose parts and foreign objects are accomplished through eddy current inspections and secondary-side foreign object search and retrieval. Removal of foreign objects is achieved in the FOSAR or in sludge lance cleaning.

## AMP Audit - B.3.26-03

GALL AMP XI.M19, Steam Generator Tube Integrity Program, references Revision 1 of NEI 97-06, "Steam Generator Program Guidelines." However, LRA AMP B.3.26, "Steam Generator Tubing Integrity Program," is implemented in accordance with Revision 2 of NEI 97-06. LRA considers this difference as an exception to the GALL AMP. Please clarify how NEI 97-06 Revision 2 differs from Revision 1. Explain how the program elements (program scope, preventive actions, detection of aging effects, and monitoring and trending) are affected by these differences. Please provide justification if any of the requirements of the program is relaxed/reduced.

## VEGP Response:

A summary of the differences between revision 1 and revision 2 of NEI 97-06, "Steam Generator Program Guidelines" is provided within revision 2 of NEI 97-06. There was no functional reduction in program requirements in this revision. While there are areas where the guidance level of detail in NEI 97-06 was reduced, in these cases the guidance is retained in, or added to, governing EPRI Guidelines referenced in NEI 97-06 or EPRI Steam Generator Management Program Administrative Procedures.

Justification for use of revision 2 of NEI 97-06 is based on staff approval of VEGP Technical Specification Amendments incorporated Technical Specification Task Force Traveler 449 revision 4, "Steam Generator Tube Integrity." As described in Generic Letter 2006-01, the NRC staff reviewed and approved TSTF-449 revision 4. In NEI correspondence with the NRC dated September 9, 2005, NEI states that Revision 2 of NEI 97-06 is consistent with TSTF-449 revision 4.

The VEGP Steam Generator Program is consistent with TSTF-449 revision 4. In a letter dated February 11, 2006 (NL-06-252), VEGP provided a response to NRC Generic Letter 2006-01. In this letter, VEGP committed to submit a proposed Technical Specifications amendment to incorporate Technical Specification Task Force Traveler TSTF-449, revision 4, Subsequently, VEGP submitted proposed amendments to the VEGP Technical Specifications sections regarding steam generator tubing integrity to incorporate TSTF-449 revision 4. The proposed Technical Specification amendments and responses to NRC staff requests for additional information were transmitted in correspondence dated March 29, 2006 (NL-06-0124), June 5, 2006 (NL-06-0990), July 20, 2006 (NL-06-0708) and August 4, 2006 (NL-06-1706). As a result of these submittals, the NRC staff issued amendments to the VEGP Technical Specifications in correspondence dated August 28, 2006 (ML062360493 - NL-06-1989) and September 12, 2006 (ML062260266 - NL-06-2084).

## AMP Audit - B.3.27-01

The program description section of AMP B.3.27, Steam Generator Program for Upper Internals, states that this program is an existing plant-specific subprogram of the VGEP Steam Generator Program. However, this program is not listed as a plant-specific program in LRA Table B2-1 (Page B-11). Provide your basis for omitting this AMP as one of the plant-specific AMPs identified in LRA Table B2-1.

## VEGP Response:

AMP B.3.27, Steam Generator Program for Upper Internals, should have appeared in LRA Table B2-1 as a plant-specific program.

A License Renewal Application amendment is required reflect this change.

## AMP Audit - B.3.28-01

The {scope of program} program element discussion in License Renewal Procedure # VEGP-LR-AMP-39 states that pH is not a detrimental ionic species and is used only as a diagnostic monitoring parameter for the Water Chemistry Control Program. Industry experience has demonstrated that excessively low pH can create an environment that promotes stress corrosion cracking in austenitic stainless steel or inconel materials and that excessively high pH can lead to create an environment that promotes caustic (base-induced) cracking in these materials. Provide your basis why pH should only be used as a diagnostic parameter and why maximum and minimum limits should not be established on pH level.

## VEGP Response:

The VEGP-LR-AMP-39 reference cited in the audit question specifically relates to sampling requirements for recirculating steam generator blowdown. The EPRI PWR Secondary Water Chemistry Guidelines sampling requirements for recirculating steam generator blowdown (as shown in 5-5 of EPRI 1008224 for operation at ≥ 30% reactor power) include pH as a diagnostic parameter, not a control parameter. It is noted that guidance for monitoring recirculating steam generator feedwater parameters (EPRI 1008224, Table 5-4) includes control of Hydrazine and pH agent concentrations, along with continuous monitoring of pH as an important diagnostic parameter.

Also, SNC clarifies that weekly pH sampling of each Unit's integrated blowdown is currently performed in addition to the online monitoring of individual steam generator blowdown line pH. If an adverse pH trend is identified, actions are taken to identify and correct the factors causing the trend.

## AMP Audit - B.3.28-02

The {parameters monitored/inspected} program element discussion in License Renewal Procedure # VEGP-LR-AMP-39 does not clarify whether Revision 5 of the EPRI Primary Water Chemistry Guidelines (i.e., EPRI Report # 1002884) provide acceptable guidelines for monitoring and controlling concentrations of chemistry control parameter species or diagnostic process monitoring or additive species in the boric acid storage tank, refueling water storage tank, spent fuel pool, letdown purification system, and chemical and volume control tank. Clarify whether these EPRI guidelines address appropriate monitoring and control guidelines for chemical control and additive species in these systems/components/tanks. If so, clarify what the parameters are and identify by reference or by direct response what the limits or specifications are for the parameters and what the sampling frequencies are for monitoring for these parameters.

## VEGP Response:

Appendix B of EPRI 1002884 addresses chemistry control practices for systems that interface with the reactor coolant system. This appendix provides suggestions for chemisty parameters to be monitored and the frequency of monitoring. There are no parameter limitation requirements or action levels included in Appendix B of EPRI 1002884 for systems that interface with the reactor coolant system. The VEGP Water Chemistry Control program considers the guidance contained in Appendix B of EPRI 1002884, along with plant operating experience and plant-specific configuration information, to establish appropriate chemistry monitoring for these systems. Generally, monitoring of these systems is focused on minimizing the potential for ingress of detrimental chemical species into the reactor coolant system.

## AMP Audit - B.3.28-03

The {operating experience} program element states that cleaning of the secondary side of the VEGP Unit 1 and Unit 2 steam generators (SGs) stated that 7000 pounds of scale were removed from the secondary side of Unit 1 SGs and 5000 pounds of scale were removed from the secondary side of Unit 2 SGs. Clarify whether a root cause analysis of the scale products (corrosion products) was ever performed to identify those chemical elements or compounds that make up the scale. If so identify those elements or compounds that made up the composition of the scale products. Identify the parameter and process controls that are established to ensure that the concentrations of these adverse elements or compounds are controlled to prevent recurrence of the scale in the SGs.

## VEGP Response:

Accumulation of corrosion products in steam generators is a common phenomena resulting from transport of corrosion products from secondary plant components to the steam generators. Years of industry experience indicate that scale and sludge products primarily consist of metal oxides from corrosion products, with the primary constituent being iron oxide. A detailed sludge analysis was performed at Vogtle and the results fall within the normal range of results as tracked within an industry database. Steam generator chemical cleaning is important for improving thermal efficiency and for preventing areas for chemical ingress that could cause localized corrosion in some areas of the steam generator. The makeup of scale is a well known and understood phenomenon in steam generators at PWRs. At VEGP, very little scale is formed due to low concentrations of feedwater iron (typically in the range of 0.7 - 0.8 ppb). VEGP is considered to be in the lower quartile of operating PWRs due to having an optimized secondary chemistry program. The amount of scale that was removed during the chemical cleaning at VEGP is well within the quantities shown in the industry database. In fact, for a 4-loop plant, these quantities were less than typical amounts removed.

**AMP Audit - B.3.28-04**

Section 4.10, "Operating Experience," of VEGP-LR-AMP-39, Water Chemistry, states that aluminum concentrations in the Spent Fuel Pool has increased since the addition of new spent fuel racks in 1998. Further, the AMP states that the new racks, installed in Unit 1's Spent Fuel Pool utilizes Boral instead of Boraflex. Additionally, the AMP states that ion exchange is effective in controlling aluminum.

LRA Section 3.3.2.2.6 Reduction of Neutron-Absorbing capacity and Loss of Material due to General Corrosion states that the presence of aluminum cladding prevents contact of the Boron Carbide materials with borated water. The conclusion is that because of the aluminum's integrity, there are no aging effects that can cause reduction of neutron-absorbing capacity for Boral. Further, the LRA states that loss of material will be managed by the Water Chemistry AMP in lieu of a plant specific AMP.

Explain the source of aluminum in the Spent Fuel Pools and clarify whether Boral is credited for maintaining K-effective (i.e., criticality) in the Spent Fuel Pools. If so, and the aluminum sheaths on the boral panels are the sources of the aluminum levels, provide your basis why it is valid to conclude that there are not any applicable aging effects for the boral panels and that aluminum impurity levels do not need to be managed in accordance with the Water Chemistry Control Program.

**VEGP Response:**

As indicated in Section 2.3.3.1 of the VEGP license renewal application and Section 4.3.2.6.1 of the VEGP FSAR, the presence of Boral panels in the Unit 1 spent fuel racks is credited in the Unit 1 criticality analyses. The Unit 2 spent fuel pool does not include Boral panels.

SNC acknowledges that aluminum concentrations in the spent fuel pool are primarily attributable to the presence of the Boral panels. However, recent aluminum concentrations in the VEGP spent fuel pool remain in the low ppb range, even without regular use of the demineralizer system.

The exterior surfaces of Boral panels are constructed from aluminum plates which are bonded to a boron carbide - aluminum matrix core. Corrosion properties of these aluminum panels are expected to be very good in a borated water environment due to formation of a protective aluminum oxide layer. This conclusion is consistent with widely available corrosion and engineering handbooks. VEGP operating experience is not inconsistent with this conclusion. Minor release of aluminum oxides into the spent fuel pool over time is an expected phenomenon.

Studies of Boral corrosion issues are presented in ERPI 1013721, "Handbook of Neutron Absorber Materials for Spent Nuclear Fuel Transportation and Storage Applications." Results of corrosion coupon weight loss studies and operating experience reviews indicate that while some corrosion will occur, corrosion significant enough to impact the boron-10 areal density of the boron carbide - aluminum matrix core is unlikely to occur.

Additionally, it is noted that the aluminum cladding is not required to prevent loss of the internal aluminum - boron carbide matrix core. The aluminum cladding serves only two principal purposes (1) as a lubricant in the hot-rolling process and (2) to facilitate handling of the long narrow panels during manufacture and assembling. Once installed in the racks and supported between stainless steel

plates, the integrity of the aluminum cladding is no longer of major significance. The core itself is considered to be suitable for exposure to borated water. As a result, loss of aluminum from the aluminum cladding due to corrosion does not necessarily result in significant loss of the neutron absorbing function of the Boral panels.

Finally, SNC monitors industry issues regarding the application of Boral through its Operating Experience and Corrective Actions Programs. Boral degradation issues within the industry are identified, assessed for applicability to VEGP, and any appropriate corrective measures implemented.

However, to ensure that possible degradation of Boral continues to be monitored, the following will be added to the SNC future action commitment list for license renewal:

"To ensure the Boral spent fuel racks will continue to perform their intended function during the period of extended operation, VEGP commits to monitor spent fuel pool aluminum concentrations and to implement corrective actions if adverse trends are identified. Additionally, SNC will monitor industry experience related to Boral and will take appropriate actions if significant degradation of Boral is identified."

## AMP Audit - B.3.29-01

10 CFR 50 Appendix J, Section IV, Special Testing Requirements, Subsection A., Containment inspection, states that a general inspection of the accessible interior and exterior surfaces of the containment structures and components shall be performed prior to any Type A test to uncover any evidence of structural deterioration which may affect either the containment structural integrity or leak-tightness. AMP B.3.29, "10 CFR 50 APPENDIX J PROGRAM" does not identify that this general containment inspection is performed. Identify and describe the VEGP program that requires this general inspection.

## VEGP Response:

A general inspection of the accessible interior and exterior surfaces of the containment structures and components prior to any Type A test is a requirement per 10 CFR 50 Appendix J Section III.A (a); Section V.A, as well as in Regulatory Guide 1.163 Section C Regulatory position 3. VEGP LRA AMP B.3.29 identifies that requirement in second and third sentence of the 3rd paragraph stating "Procedures require a general visual inspection of the accessible interior and exterior surfaces of the primary containment and components prior to each integrated leak rate test pressurization. In addition, visual examinations of containment, as described in Regulatory Guide 1.163, are performed in the period between Type A tests."

Also, VEGP Containment Integrated Leak Rate Test procedures 84400-2 list that requirement in Section 4.1.1 as a prerequisite.

## AMP Audit - B.3.30-01

Explain why the VEGP AMP B.3.30, Inservice Inspection Program - IWE element Parameters Monitored or Inspected does not appear to credit any inspection of non-coated primary containment surfaces. Specifically clarify whether or not this program credits the requirements of ASME Section XI paragraph IWE-2310 to monitor for evidence of discoloration, pitting, gouges, surface discontinuities, dents, and other signs of surface irregularities in non-coated containment liner areas.

## VEGP Response:

Yes, the ISI-IWE program is credited for inspection of non-coated containment liner areas. The inspection of non-coated areas examines for evidence of cracking, discoloration, wear, pitting, excessive corrosion, arc strikes, gouges, surface discontinuities, dents and other signs of surface irregularities, which includes the requirements of ASME Section XI paragraph IWE-2310.

SNC notes that the visible VEGP primary containment and attachments steel surfaces are coated with a qualified coating. VEGP does not credit coatings for aging management. The protective effects of coatings are not credited when the aging effects requiring management are determined for the underlying component materials. The ISI - IWE program inspections of these coated containment liner surfaces, which examine for evidence of flaking, blistering, peeling, discoloration, and other signs of distress, are credited for license renewal for identify potential degradation of the underlying liner material.

## AMP Audit - B.3.30-02

The detection of aging effects program element for GALL AMP XI.S1, ASME Section XI, Subsection IWE; states that ASME Section XI paragraph IWE-1240 requires augmented examinations of containment surface areas that are subject to degradation. Under the VEGP Inservice Inspection Program - IWE, explain historically what inspection findings have lead to the need for augmented inspections of the AMP. Explain if any augmented inspections are currently being performed of the containment surfaces, and if so, clarify the containment locations are within the scope of the augmented inspections and what the inspections involve!

## VEGP Response:

IWE-1241 requires augmented examinations of interior and exterior containment surface areas subjected to (a) accelerated corrosion with no or minimal corrosion allowance, and (b) excessive wear from abrasion or erosion that causes a loss of protective coatings, deformation, or material loss. The VEGP IWE inspections have not identified any areas which require augmented examination.

Although not an augmented inspection, the liner plate was examined following the removal of a portion the moisture seal. As identified in the 1R9 NIS (Nuclear Inspection Service) Report, a small area of the moisture seal was removed following the identification of surface rust at the mating surface between the moisture seal and the containment liner plate. The liner plate was examined following the removal of the moisture seal and no liner plate damage was found. As a good practice since 1R9, VEGP performs a VT-3 of 100% of the moisture barrier every period and UT measurements of liner plate thickness at different locations.

# Vogtle License Renewal Audit Questions and Answers

## AMP Audit - B.3.31-01

GALL AMP XI.S2, ASME Section XI, Subsection IWL; states under element Detection of Aging Effects that the frequency and scope of examinations specified in 10 CFR 50.55a and Subsection IWL ensure that aging effects would be detected before they would compromise the design-basis requirements. The frequency of inspections is specified in IWL-2400. A review of the tendon data provided in LRA Section 4.5 Concrete Containment Tendon Pre-stress shows that based on the tendon lift-off initial testing dates; the program probably started out under Regulatory Guide 1.35 Revision 2. A review of the tendon lift-off dates after initial testing indicates that the program might have transitioned to under Regulatory Guide 1.35 Revision 3. Finally and currently, the tendon lift-off dates are based on ASME Section XI, Subsection IWL criteria. Explain how the tendon lift-off testing dates were selected and the periodicity for the tests changed for each Unit based on the different program guidance that VEGP followed over time (which finally transitioned to the 5 year staggered 10 year tendon testing periodicity for each unit).

## VEGP Response:

During the initial years of plant operation, Regulatory Guide 1.35 Rev. 2 (January 1976) was followed as the basis for tendon surveillance. The Regulatory Guide stated that inservice inspection be performed 1, 3, 5 years after the Initial Structural Integrity Test (ISIT) and every 5 years thereafter. Needed only visual inspection for identical unit.

In 1989, an amendment to the VEGP Technical Specifications (Amendments No 23 and No. 4 for Units 1 and 2, respectively) incorporated a schedule proposed by SNC and approved by the NRC.

With the adoption of ASME Section XI, Subsection IWL 1992 Edition (as mandated by 10CFR 50.55a), Vogtle implemented the IWL 2421 requirements starting with the inspections performed in 2000.

Based on the above, the VEGP Tendon Inspection Schedule is as follows:

| **Unit 1** | | | **Unit 2** | | |
|---|---|---|---|---|---|
| **Examination Date** | **Lift Off?** | **Detail** | **Examination Date** | **Lift Off?** | **Detail** |
| January 1988 | Yes | Tendon (L-B) - 1$^{ST}$ Year | | | |
| Sep - Nov 1989 | Yes | Tendon (L-B) - 3$^{RD}$ Year | Oct - Nov 1989 | No | Tendon (L-B) - 1$^{ST}$ Year |
| Sept - Oct 1991 | No | Tendon (L-B) - 5$^{TH}$ Year | Sept - Oct 1991 | Yes | Tendon (L-B) - 3$^{RD}$ Year |
| June-Aug 1995 | No | Tendon (L-B) - 10$^{TH}$ Year | June-Aug 1995 | Yes | Tendon (L-B) - 5$^{TH}$ Year |
| June 2000 | Yes | Tendon (L-B) - 15$^{TH}$ Year | May 2000 / Spring 2001 | No | Tendon (L-B) - 10$^{TH}$ Year |
| July 2005 | No | Tendon (L-B) - 20$^{TH}$ Year | July 2005 | Yes | Tendon (L-B) - 15$^{TH}$ Year |
| July 2010 | Yes | Tendon (L-B) - 25$^{TH}$ Year | July 2010 | No | Tendon (L-B) - 20$^{TH}$ Year |
| July 2015 | No | Tendon (L-B) - 30$^{TH}$ Year | July 2015 | Yes | Tendon (L-B) - 25$^{TH}$ Year |
| July 2020 | Yes | Tendon (L-B) - 35$^{TH}$ Year | July 2020 | No | Tendon (L-B) - 30$^{TH}$ Year |

## AMP Audit - B.3.31-02

A review of the tendon data for year 2005, as provided in Table 4.5-2 of LRA Section 4.5, Concrete Containment Tendon Pre-stress, shows that the predicted average tendon force is different for individual Unit 2 inverted U vertical tendons. Also in LRA Table 4.5-4 for year 2005, the predicted average tendon force is different for individual Unit 2 horizontal (shell) hoop tendons. This phenomenon only appears in these two tables for the year 2005. Explain why the predicted average tendon force varies by individual tendon in these two tables for year 2005

## VEGP Response:

The predicted average tendon forces in Table 4.5-2 for the individual Unit 2 inverted U vertical tendons are incorrect. The correct values should be 1463 Kips for Tendon No. V20-92, V21-91 and V56-130.

The predicted average tendon forces in Table 4.5-4 for the individual Unit 2 horizontal (shell) hoop tendons are incorrect. The correct values should be 1427 Kips for Tendon No. H-66, H-99 and H-111.

These changes do not affect the graphs given in the LRA. The graphs are drawn based on actual data not the predicted data.

A license renewal amendment is required.

## AMP Audit - B.3.32-01

In LRA AMP B.3.32, "Structures Monitoring Program," under enhancements section, the applicant states that for program elements 3, 5, and 6, the Structures Monitoring Program will be enhanced to include periodic ground water monitoring to confirm it remains non-aggressive. Please clarify the ground water monitoring frequency and its basis to confirm it remains non-aggressive.

Additional Request:
Provide date of most recent ground water monitoring and provide results of this monitoring.

**VEGP Response:**

Structures Monitoring Program will be enhanced to perform ground water monitoring at a maximum interval of five years irrespective of whether the below grade environment is aggressive or not. Initially, this period is set at five years based on the non-aggressive nature of under ground environment noted so far. Ground water monitoring frequency may be subject to modification (increased monitoring) based on plant specific environments, observed degradation or noticeable change in ground water chemistry. Ground water is considered aggressive when environmental conditions exceed threshold values (Chlorides > 500 ppm, Sulfates >1500 ppm, and pH < 5.5).

| Chemical Parameter | Groundwater | | |
|---|---|---|---|
| | FSAR (1) | Recent Lab Test (2) | Recent Lab Test (3) |
| pH | 6.1 - 11.3 | 7.42 - 8.24 | 5.77 - 6.34 |
| Chlorides (ppm) | 1.0 - 198.4 | 1.95 - 8.71 | 4.97 - 7.95 |
| Sulfates (ppm) | 3.6 - 36.6 | 2.9 - 12.5 | 1.63 - 11.95 |

Notes:

(1) Refer FSAR Section 2.4 Table 2.4.12-3
(2) Recent test has been conducted by General Test Laboratory between 11/2/05 to 11/21/05.
(3) Recent test has been conducted by General Test Laboratory between 05/08/07 to 05/09/07.

**AMP Audit - B.3.32-02**

In regard to the LRA AMP B.3.32 "operating experience" program element, provide the basis for selecting a 10-Year inspection frequency based on 1998, 2000, and 2005 Structures Program inspections.

**VEGP Response:**

The Structural Monitoring Program provides the assurance of the functionality of structures which are under the scope of the Maintenance Rule as defined in 10 CFR 50.65. This is accomplished by providing an effective method to monitor structural performance through representative periodic inspections along with the identification and trending of potential structural deficiencies. The goal of this program is to demonstrate that acceptable structural performance is maintained and that the identified structures remain capable of performing their intended function.

This program consists of two phases: 1) obtaining baseline data and 2) performing periodic inspections. The baseline data was obtained from inspections that were conducted between 1998 and 2000. The schedule for the periodic inspections was determined based on the results of the baseline inspections.

Also, the frequency of a periodic inspection is determined considering data obtained during previous inspections, aggressiveness of environmental conditions, industry-wide operating experience, industry events, and physical conditions of the plant structures and structural components.

SMP Review of Baseline Observations to Determine Periodic Inspection Intervals:

Based on a review of SMP baseline data, the overall condition of Plant Vogtle's structures and structural components, and the lack of aggressive environments, the initial periodic inspection period for a majority of the structures and structural components were set on a 10-year period. Other basis for this 10-year period includes the following.

1. Initial baseline inspections were conducted during the period when Plant Vogtle had been in operation for approximately 10 years. As a result, the baseline inspections included 10 years of degradation during normal operation conditions plus the degradation that occurred during the initial construction period.

2. Maintenance and housekeeping at Plant Vogtle are conducted on a routine basis. Therefore, some degradation mechanisms are removed prior to their impact on surrounding structures and structural components. In addition, active degradation is observed during early stages and appropriate correction actions are implemented prior to the occurrence of significant degradation.

Beginning in April 2000, all structures and structural components that were inspected during the baseline inspections are to be re-inspected at least once during the next 10 years (i.e., ending April 2010). Based on the results of the baseline inspections, those structures and structural components that were identified as having some significant amount of degradation and/or susceptible environment are re-inspected on shorter intervals (i.e.; 1 year, 2 years, etc.) and possibly inspected several times during the 10 year period. Structures and structural components having the more frequent inspection intervals were inspected first, followed by those structures and structural components with a ten-year interval.

The following Table lists some of the areas/structures which are currently inspected on shorter intervals than 120 months:

| Area/ Structures | Inspection Interval (months) |
|---|---|
| Turbine Building Level 3 North Side of Turbine Pedestal | 24 |
| Containment Tendon Gallery | 24 |
| Control Building Roof | 24 |
| Turbine Building Level A Tank and Pump Pads | 24 |
| NSCW Tower Valve House | 24 |
| Turbine Building Level 1 R-222 | 24 |
| Diesel Exhaust Silencer Pads | 24 |
| NSCW Tower Valve House | 24 |
| Diesel Exhaust Enclosures | 12 |
| Containment Reactor Cavity | 36 |
| Containment El. 171'-9" ISSW | 18 |
| Containment Polar Crane Rail Area | 18 |
| Containment Pressurizer Compartment | 18 |
| Containment Lower Level A and B | 18 |
| Containment Polar Crane Rail Area | 18 |
| Containment El. 238'-0" Platform | 18 |

**AMP Audit - B.3.35-01**

In LRA AMP B.3.35, "Non-EQ Inaccesible Medium-Voltage Cable Program, the applicant states that this program is new with no site-specific operating experience history. The SRP-LR, Revision 1, Appendix A, Branch Technical Position RLSB-1 states that an applicant may have to commit to providing operating experience in the future for new program to confirm their effectiveness. Describe how operating experience will be captured to confirm the program effectiveness and the process to be used to adjust the program as needed.

**VEGP Response:**

Industry and plant-specific operating experience will be considered when implementing this program. VEGP has ongoing programs to monitor industry and site operating experience. These programs include mechanisms to update or modify plant procedures or practices to incorporate lessons learned.

Procedures NMP-GM-008, "Operating Experience Program," and 50026-C, "ESD - Operating Experience Program," describe the program for evaluating industry and vendor-supplied operating experience. Operating experience information that is identified as being applicable to VEGP is disseminated to the appropriate groups for further evaluation and possible modification of plant procedures or practices.

If an unacceptable condition or situation is identified in the selected sample, the Corrective Action Program will be used to evaluate the condition and determine appropriate correction action. This corrective action will involve a determination as to whether the same condition or situation is applicable to other cables and connections not in the sample population.

Section B3.35 of the LRA will be revised to indicate that both industry and plant specific OE will be reviewed for this program.

A License Renewal application amendment is required.

# Vogtle License Renewal Audit Questions and Answers

**AMP Audit - B.3.35-02**

VEGP-LR-AMP-24 document identifies two medium cables within the scope of license renewal that are managed by Non-EQ Inaccessible Medium-voltage Cables Program. Please provide your evaluations including results of any plant walk downs to show how the medium -voltage cables were screened out .

**VEGP Response:**

The following method was used to determine which medium-voltage power cables (4kV and above) might be subject to being submerged in water while continuously energized (energized more than 25% of the time):

1. Determine all pull boxes (man-holes) that have a voltage level of 4kV or above
2. Find the "included cables" for the above pull boxes (man-holes)
3. Review the list of cables to determine which cables are in-scope for LR
4. For the in-scope cables, determine which ones are continuously energized
5. For the continuously energized, 4kV, in-scope cables above, determine if any of the pull boxes (man-holes) allow the cables to become submerged for significant periods of time.

The Plant Data Management System (PDMS) database was searched to accomplish steps 1 and 2 and to find single line and elementary drawings for step 3. The Vogtle single line and elementaries were reviewed in step 3 and it was determined that the only 4kV, underground, continuously energized cables that were potentially submerged were two feeders to the high voltage switchyard.

# Vogtle License Renewal Audit Questions and Answers

**AMP Audit - B.3.36-01**

In LRA AMP B.3.36, "Non-EQ Cable Connections One-time Inspection Program," under "Program Description", "and Detection of Aging Effects," Sections, the applicant states that the inspections will be performed within a window of five years immediately preceding the period of extended operation for the first unit (Unit 1) and in the following paragraph, the applicant states that the inspections will be performed within a window of ten years immediately preceding the period of extended operation." Please clarify when this one-time inspection will be completed for each of the VEGP Units and your plans to correct the conflicting statements in the LRA.

**VEGP Response:**

The inspections for both units will be performed within a window of five years immediately preceding the period of extended operation.

Reference Enclosure 2 to letter NL-07-1261 - VEGP License Renewal Future Action Commitment List, item 27.

A License Renewal Application amendment is required to correct this discrepancy.

**AMP Audit - B.3.36-02**

In LRA, Appendix B, Section B.3.36, "Non-EQ Cable Connections One-time Inspection Program," under "Detection of Aging Effects," the applicant states that the inspection methods may include visual inspection. Please explain how visual inspection will be able to provide an indication of the integrity of the cable connections.

**VEGP Response:**

Section B.3.36 of the LRA will be revised to state that the inspection may include thermography, contact resistance testing, or other appropriate methods.

A License Renewal application amendment is required.

# Vogtle License Renewal Audit Questions and Answers

**AMP Audit - B.3.37-01**

In LRA, Appendix B, Section 3.37, the applicant states that the VEGP EQ program is maintained in a qualified condition. Discuss the details of key operating experience, self-assessments, QA audits and condition reports that led to this conclusion. Show where an existing program has succeeded and where it has failed in identifying aging degradation in a timely manner with the present program.

**VEGP Response:**

Operating Experience (OE) is addressed in EQ Program Procedure NMP-ES-016 (Paragraph 6.4.2). The procedure states that lessons learned from industry and fleet OE shall be evaluated to improve safety and reliability. INPO OE16176 was issued to notify Licensees that low insulation resistance during LOCA/HELB conditions may degrade valve position indication. An evaluation of this condition revealed that the problem existed with Limitorque actuators using limit switches with melamine finger bases. This OE was evaluated under RER 2004-V0398, which recommended that the melamine be replaced with fiberite material that performs well in the presence of steam conditions. As a result, Action Item 2004250667 was created to revise maintenance procedures to reflect this change and Work Order C049639801 was created to replace the finger bases.

Another OE involved a Part 21 on Barton transmitters with a potential insulation defect in the lead wire. The Barton transmitters within EQ scope were identified for harsh environment locations with postulated steam line breaks. To resolve this OE, Vogtle Unit 1 and Unit 2 DCPs 1061854401 and 206198880, respectively, were prepared to add an environmental seal (Patel seal) to the Barton transmitters to prevent moisture intrusion. To date 8 of 10 Patel seals have been installed on Unit 1 Barton transmitters and the other 2 are scheduled for installation during the 1R14 refueling outage in the Spring of 2008. On Unit 2, the Patel seals have already been installed on all 10 Barton transmitters.

INPO OE23516 was issued on Cinch-Jones terminal strips to identify a potential for premature failure of terminal strips located in the hot box. This OE was evaluated under action item AI 2007200143 and no change was required to the qualified life because the qualified life analysis already included the heat rise. However, for future reference, an EQ change package (EQ-3203) was incorporated into EQDP X5AA05.

Self-assessments of the EQ Program are addressed in Procedure NMP-ES-016 (Paragraph 6.5). The procedure states that the Technical Team shall perform periodic self-assessments. The most recent self-assessment was performed in June, 2005. The self-assessment team included the EQ Technical Team (Corporate EQ personnel and site EQ personnel) and 3 industry peers from Duane Arnold, Brunswick, and Crystal River. The scope of the assessment included all fleet locations and all processes that interface with the EQ Program. The assessment also included walk downs of selected EQ equipment to verify proper installation.

The EQ Program is audited by the internal QA organization every 2 years, which is documented in QA procedure NMP-QA-104 (Planning and Scheduling). The most recent QA audit of the EQ Program was performed between May 1, 2006 and June 7, 2006, and documented in QA Report (Log CQA-2006-095) dated June 9, 2006. The QA audit resulted in no findings for the EQ Program, but one recommendation was made. The recommendation was documented in CR 2006100362, which indicated that design basis documentation (i.e., calculations) should be used as design input rather than licensing basis documentation (i.e., FSAR). Therefore, training was provided to EQ personnel on July 5, 2006, emphasizing the use of design references rather than licensing references as design inputs.

More than 20 condition reports and 14 action items have been generated to improve, modify, or correct the Vogtle EQ Program documentation over the last four years. Since plant start-up, there have been over 3,240 EQ change packages generated for the EQ Central File. The CRs, AIs, and EQ change packages are indicative of an active EQ Program that is being continuously updated with the latest information and improvements available.

Success of the program has been demonstrated through self-assessments, walk downs, and OE review to identify weaknesses. The most significant issue discovered during the June, 2005, self-assessment involved 2 Rosemount transmitters with rotated heads (electronic housing) which could break the neck seal and allow moisture intrusion into the electronic housing. Subsequently, all Rosemount transmitters located in steam line break locations were walked down and an additional 6 transmitters were identified. These 8 transmitters were all replaced by November 6, 2006. Site procedures related to replacement and calibration of the Rosemount transmitters now include a warning not to rotate the head during installation or calibration. A similar warning has also been placed in the EQ Central File. Subsequent to replacement of the initial 8 transmitters, two additional transmitters with rotated heads were identified and replaced. The corrective actions were then revised to create a formal maintenance process (Reptask) for the removal and installation of temporary protective covers labeled with cautions at designated times during refueling outages. In addition, a Request for Engineering Review (RER) has been created for Engineering to identify alternatives to protect and prevent the rotated head problem.

The program failed to identify aging degradation in a timely manner associated with the main steam isolation valve (MSIV) actuators. The MSIVs were discovered in the early to mid 1990s to drift to the closed position every other year only during the hot summer months. The MSIVs use electro-hydraulic actuators with Frequel hydraulic fluid and Keane solenoid valves are used to control the hydraulic fluid and operation of the valve. Based on a temperature monitoring survey, it was discovered that the MSIV actuators experienced local hot spots in the area of the Keane solenoid valves and lower Namco limit switches.

A failure analysis was performed on the Keane solenoid valves and the Namco limit switches were requalified for the elevated temperatures. In addition, a maintenance requirement was incorporated into the PM Program to inspect the Okonite cable for signs of degradation whenever the limit switches are replaced. The failure analysis on the solenoid valves revealed that the valves had brass seats that were susceptible to corrosion from the hydraulic fluid which contained chlorides. The chlorides mixed with moisture in the hydraulic reservoir which resulted in hydrolysis and the formation of hydrochloric acid. The acid attacked the brass seats and severely pitted the brass surface which made it easy for the fluid to flow across the seats since the fluid was less viscous (thinner) due to the elevated temperatures. A design change was made to replace the brass seats with Vespel which is not susceptible to corrosion and a filter was installed on the reservoir to prevent moisture intrusion into the fluid. Subsequently, the Keane solenoid valves were requalified for the elevated temperatures with the Vespel seats. To reduce the temperatures on the MSIV actuators, a design change was implemented to install a blower to blow cool air across the actuators.

# Vogtle License Renewal Audit Questions and Answers

**AMP Audit - B.3.38-01**

Please provide the triggering point/s for each component and transient cycle monitored under the Fatigue Monitoring Program and describe the process by which the applicant takes when a component approaches its triggering point. Please also provide the periodicity of plant review as well as describe the review process of component fatigue data and transient cycles.

**VEGP Response:**

SNC assumes that "triggering point/s" means the point for each component and each cycle where corrective action is initiated. For each cycle monitored, corrective action is initiated when the 60-year projected cycles exceed the cyclic or design limit shown in Table 4.3.1-2 of the LRA. For each component monitored for fatigue, corrective action is initiated when the 60-year projected CUF exceeds the allowed CUF, which is 1.0 for all monitored components, except those that were evaluated for environmental fatigue. The allowed CUF for components evaluated for environmental fatigue is shown in Table 4.3.1-3 of the LRA. In addition, procedure 83101-C, Version 11.1, Section 6.1.2 requires that any transient which is at 75% of the design number is reviewed to determine the need for further evaluation or corrective action. Counted and projected plant cycles and component CUFs are evaluated once per 18 months per Section 5.1.5 of procedure 83101-C.

**AMP Audit - B.3.38-02**

Please describe the corrective actions when a component exceeds its design limits, including whether or not this meant placing such component in the plant's corrective action programs.

**VEGP Response:**

SNC understands "design limit" in this question to mean exceeding design cycles for cycle monitoring or a CUF greater than 1.0 for those components monitored for CUF. SNC's Fatigue Monitoring Program is intended to take corrective action before a component exceeds its design limits. If a component were to exceed its design limit, the plant's corrective action program would be entered. In such a case, the CR would address whether the plant could continue to operate, identify appropriate corrective actions to restore the component, make a determination of other affected components, and include a root cause evaluation of how the corrective action program failed to prevent the component from exceeding its design limit.

It is SNC's intent that no component will actually exceed its design limit. For that reason, SNC initiates corrective actions whenever the 60-year projection for that component exceeds the design limit. Corrective actions because a projected value is higher than the design limit could include a variety of responses depending on the length of time between the identification that a design limit is projected to be exceeded and when the design limit is projected to be exceeded. Acceptable corrective actions may include alternative monitoring (e.g., monitoring CUF of the bounding location rather than monitor the cycle), a more rigorous analysis of the component to demonstrate that the ASME Section III design limit will not be exceeded, repair, or replacement of the component. Another corrective action alternative is an inspection program.

# Vogtle License Renewal Audit Questions and Answers

**AMP Audit - B.3.38-03**

LRA Section B.3.38 states, "Fluid leakage is detected by temperature measurement utilizing resistance temperature detectors (RTDs) strapped on the pipe. The temperature data is periodically recorded and evaluated for thermal stratification and cycling to determine its impact on piping structural integrity." However, the operating experience from those activities is not described in the LRA.

a. Please provide the interval for recording the temperature data and indicate any follow-up evaluation for thermal stratification and cycling as result of monitoring.

b. Operating experience section in the LRA B.3.38 do not contain any experience on temperature measurement, please provide/describe them.

c. Please list and describe all components monitored under the Thermal Stratification Data Collection Program, including the periodicity of monitoring for each of the components.

**VEGP Response:**

a. Per plant procedure 83303-C, locations monitored for thermal stratification are monitored on 10 minute intervals for a 24 hour period, once every six months. More frequent monitoring may be established by direction of the Engineering Support Manager. Data collection intervals may be revised with the concurrence of the Engineering Support Manager.

b. The VEGP program for thermal stratification monitoring was established in response to IEB 88-08 and IEB 88-11 and incorporates industry operating experience. At one time, the program included monitoring of the pressurizer surge line to study the stratification of the surge line. That information was used to develop design transients for the surge line that include thermal stratification effects. The NRC accepted VEGP's approach to resolve surge line thermal stratification for both units in Vogtle Unit 1 Safety Evaluation on Pressurizer Surge Line Thermal Stratification (NRC Bulletin 88-11) (TAC 72178) dated April 12, 1990. After receiving that SER, VEGP stopped monitoring the surge line RTDs. The RTDs installed on the surge line have been retired in place. (VEGP continues to monitor the surge line CUF with FatiguePro that accounts for any thermal stratification in the calculated CUF.)

   In recent years, there has only been one instance where the RTDs installed for 88-08 monitoring have indicated a problem. That was in November 2006 on the Unit 2 RHR line. Condition Report 2006113276 documents that the RTD on the bonnet of 2HV8701B was approximately 180°F hotter than normal. Also, another RTD located on the bottom of the RHR pipe, approximately 4 inches upstream from 2HV8701B was about 15°F higher than normal. OE from Genkai that is described in IEB 88-08 Supplement 3 was evaluated and it was determined that this situation was not due to the same situation as at Genkai, but rather was due to a steady packing leak. The valve was repacked, and thermal stratification data was gathered and analyzed on a weekly basis for several weeks. Evaluation of that data determined that the problem was corrected.

   Due to cracking on the Unit 2 RHR bypass line, Action Item 2007202917 temperature data from April 2006 to January 2007 on Unit 2 were reviewed to determine whether thermal stratification is occurring downstream of the first closed isolation valve in the supply line. The data consisted of temperature readings at points at the top and bottom of the pipe, upstream and downstream of the isolation valve, on each loop. It was concluded that there was no significant stratification occurring in the monitored lines.

c. The following instruments associated with Unit 1 unisolable RCS piping locations are monitored for thermal stratification in response to Bulletin 88-08, on 10 minute intervals for a 24 hour period, once every six months in accordance with procedure 83303-C, Version 4.1.

| Instrument Tag Number | Keithley Channel Number | Line Number | Line Description | Position on Pipe |
|---|---|---|---|---|
| 1TE-27734 | 101 | 1208-009-3" | Normal Chg. | Top (0°) |
| 1TE-27735 | 102 | 1208-009-3" | Normal Chg. | Bottom (180°) |
| 1TE-27736 | 103 | 1208-007-3" | Alt. Charging | Top (0°) |
| 1TE-27737 | 104 | 1208-007-3" | Alt. Charging | Bottom (180°) |
| 1TE-27738 | 105 | 1208-012-2" | Aux. Spray | Top (0°) |
| 1TE-27739 | 106 | 1208-012-2" | Aux. Spray | Bottom (180°) |
| 1TE-27740 | 107 | 1204-243-1 1/2" | SIS BIT Line | Top (0°) |
| 1TE-27741 | 108 | 1204-243-1 1/2" | SIS BIT Line | Bottom (180°) |
| 1TE-27742 | 109 | 1204-246-1 1/2" | SIS BIT Line | Top (0°) |
| 1TE-27743 | 110 | 1204-246-1 1/2" | SIS BIT Line | Bottom (180°) |
| 1TE-27744 | 111 | 1204-244-1 1/2" | SIS BIT Line | Top (0°) |
| 1TE-27745 | 112 | 1204-244-1 1/2" | SIS BIT Line | Bottom (180°) |
| 1TE-27746 | 113 | 1204-245-1 1/2" | SIS BIT Line | Top (0°) |
| 1TE-27747 | 114 | 1204-245-1 1/2" | SIS BIT Line | Bottom (180°) |

The following instruments associated with Unit 2 unisolable RCS piping and RHR piping locations are monitored for thermal stratification in response to Bulletin 88-08, on 10 minute intervals for a 24 hour period, once every six months in accordance with procedure 83303-C, Version 4.1.

| Instrument Tag Number | Keithley Channel Number | Line Number | Line Description | Position on Pipe |
|---|---|---|---|---|
| 2TE-27734 | 101 | 1208-009-3" | Normal Chg. | Top (0°) |
| 2TE-27735 | 102 | 1208-009-3" | Normal Chg. | Bottom (180°) |
| 2TE-27736 | 103 | 1208-007-3" | Alt. Charging | Top |
| 2TE-27737 | 104 | 1208-007-3" | Alt. Charging | Bottom |
| 2TE-27738 | 105 | 1208-012-2" | Aux. Spray | Top |
| 2TE-27739 | 106 | 1208-012-2" | Aux. Spray | Bottom |
| 2TE-27740 | 107 | 1204-243-1½" | SIS BIT Line | Top |
| 2TE-27741 | 108 | 1204-243-1½" | SIS BIT Line | Bottom |
| 2TE-27742 | 109 | 1204-246-1½" | SIS BIT Line | Top |
| 2TE-27743 | 110 | 1204-244-1½" | SIS BIT Line | Bottom |
| 2TE-27744 | 111 | 1204-244-1½" | SIS BIT Line | Top |
| 2TE-27745 | 112 | 1204-244-1½" | SIS BIT Line | Bottom |
| 2TE-27746 | 113 | 1204-245-1½" | SIS BIT Line | Top |
| 2TE-27747 | 114 | 1204-245-1½" | SIS BIT Line | Bottom |
| 2TE-27748 | 115 | 1201-049-12" | RHR Recirc | Top |
| 2TE-27749 | 116 | 1201-049-12" | RHR Recirc | 90° |
| 2TE-27750 | 117 | 1201-049-12" | RHR Recirc | Bottom |

| Instrument Tag Number | Keithley Channel Number | Line Number | Line Description | Position on Pipe |
|---|---|---|---|---|
| 2TE-27751 | 118 | 1201-049-12" | RHR Recirc | 60° |
| 2TE-27752 | 119 | 1201-049-12" | RHR Recirc | 120° |
| 2TE-27753 | 120 | 1201-049-12" | RHR Suction | Top |
| 2TE-27754 | 201 | 1201-049-12" | RHR Suction | Bottom |
| 2TE-27755 | 202 | 1201-049-12" | RHR Suction | Top |
| 2TE-27756 | 203 | 1201-251-½" | RHR Leakoff | Bottom |
| 2TE-27757 | 204 | 1201-049-12" | RHR Suction | Top |
| 2TE-27758 | 205 | 1201-036-12" | RHR Recirc | Top |
| 2TE-27759 | 206 | 1201-036-12" | RHR Recirc | 90° |
| 2TE-27760 | 207 | 1201-036-12" | RHR Recirc | Bottom |
| 2TE-27761 | 208 | 1201-036-12" | RHR Recirc | Bottom |
| 2TE-27762 | 209 | 1201-036-12" | RHR Recirc | Top |
| 2TE-27763 | 210 | 1201-036-12" | RHR Suction | Top |
| 2TE-27764 | 211 | 1201-036-12" | RHR Suction | Bottom |
| 2TE-27765 | 212 | 1201-036-12" | RHR Suction | Top |
| 2TE-27766 | 213 | 1201-249-½" | RHR Leakoff | Bottom |

**AMP Audit - B.3.38-04**

Section B.3.38 of the VEGP license renewal application mentions SBF monitoring. Please provide a list of components that rely on SBF monitoring by the Fatigue Monitoring Program to disposition the fatigue TLAA for those components.

**VEGP Response:**

Section B.3.38 of the LRA will be amended to list those components that require SBF monitoring during the period of extended operation because the disposition of the fatigue TLAA for those components credits the Fatigue Monitoring Program for aging management. Those components are:

- Main and auxiliary feedwater nozzles
- Normal and alternate charging nozzles on the cold legs
- Hot leg surge nozzles
- Pressurizer lower heads (Heater Penetration is the bounding location)
- Pressurizer surge nozzles
- Accumulator/RHR nozzles on the cold legs

A License Renewal Application amendment is required.

**AMP Audit - B.3.38-05**

Section B.3.38 of the VEGP license renewal application states in the discussion of "Fatigue Monitoring Requirements Due To Environmentally Assisted Fatigue, "All locations evaluated were shown to be acceptable for 60 years." Please explain, for each of the evaluated locations, how they were shown to be acceptable.

**VEGP Response:**

Section B.3.38 of the LRA will be amended to explain how each of the locations evaluated for environmentally assisted fatigue was shown to be acceptable for 60 years as described below.

The reactor vessel lower head to shell juncture and reactor vessel inlet and outlet nozzles were shown to be acceptable for 60 years by multiplying the maximum applicable $F_{en}$ of 2.45 times the design CUF for each component and determining that value to be less than 0.5 which allows margin for 60 years.

The surge line hot leg nozzles and the RHR line inlet transition nozzles (Accumulator/RHR nozzle at VEGP) were shown to be acceptable for 60 years by multiplying the maximum applicable $F_{en}$ of 15.35 times the 60-year projected CUF from the fatigue management software and determining that value to be less than 1. These locations will be managed under the Fatigue Management Program to ensure that the projected CUF times maximum Fen remains below 1.

The normal and alternate charging nozzles and the safety injection nozzles were shown to be acceptable for 60 years by calculating an integrated strain rate Fen for each location, multiplying that $F_{en}$ value times the 60-year projected CUF from the fatigue management software for each nozzle and determining the result to be less than 1. These locations will be managed under the Fatigue Management Program to ensure that the projected CUF times integrated strain rate Fen remains below 1.

A License Renewal Application amendment is required.

**AMP Audit - B.3.38-06**

Section B.3.38 of the VEGP license Renewal application states that various program enhancements will be implemented prior to the period of extended operation. The staff must verify that these enhancements have been implemented prior to the period of extended operation. The staff would like clarification on when these enhancements will be implemented.

**VEGP Response:**

The LRA will be amended to reflect that the enhancements to the Fatigue Monitoring Program will be implemented at least two years prior to the period of extended operation. The Future Actions Commitment List will also be revised to reflect the timing of these enhancements.

An amendment to the license renewal application is required.