VIRGINIA ELECTRIC AND POWER COMPANY
RICHMOND, VIRGINIA 23261

May 22, 2002

United States Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555-0001

Serial No.: 02-277
LR/MWH R0
Docket Nos.: 50-280/281
50-338/339
License Nos.: DPR-32/37
NPF-4/7

Gentlemen:

VIRGINIA ELECTRIC AND POWER COMPANY (DOMINION)
SURRY AND NORTH ANNA POWER STATIONS UNITS 1 AND 2
REVIEW AND CONCURRENCE WITH NRC SUMMARY OF TELECOMMUNICATION LETTERS
LICENSE RENEWAL APPLICATIONS

The NRC staff has requested Virginia Electric and Power Company (Dominion) to perform a formal review of NRC letters issued to summarize telecommunications held to discuss the Surry and North Anna License Renewal Applications. This submittal documents the review of the attached three (3) NRC letters dated August 8, 2001, October 11, 2001, and January 30, 2002 (assigned Dominion serial numbers 01-518, 01-659, and 02-122, respectively) by Dominion staff. During the review, we found the Dominion statements made during the telecommunications to be accurately documented in the attached letters with two clarifications:

1. In the letter dated August 8, 2001, Item 2 on page 2 should be clarified that the AAC Diesel Starting Air System supports the AAC diesel-generator as opposed to the emergency diesel generators (EDG).

2. Also in the letter dated August 8, 2001, Item 5 on page 3 should be clarified to note that the local emergency operating facility (LEOF) continues to fulfill the emergency planning function as a response facility. As such, the LEOF provides facilities for an active response of state and licensee teams in emergency situations. This clarification does not change the stated conclusion that the LEOF is not within the scope of license renewal.

A086

Should you have any questions regarding this submittal, please contact Mr. J. E. Wroniewicz at (804) 273-2186.

Very truly yours,

David A. Christian
Senior Vice President – Nuclear Operations and Chief Nuclear Officer

Attachments

Commitments made in this letter: None

cc: (w/o attachment)

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COMMONWEALTH OF VIRGINIA)
)
COUNTY OF HENRICO)

The foregoing document was acknowledged before me, in and for the County and Commonwealth aforesaid, today by David A. Christian who is Senior Vice President and Chief Nuclear Officer of Virginia Electric and Power Company. He has affirmed before me that he is duly authorized to execute and file the foregoing document in behalf of that Company, and that the statements in the document are true to the best of his knowledge and belief.

Acknowledged before me this 22nd day of May, 2002.

My Commission Expires: 3-31-04.

Maggie McClure

Notary Public

(SEAL)

Attachment 1

License Renewal – Review of NRC Letters
Serial No. 02-277

NRC Letter dated August 8, 2001
Summary of July 31, 2001 Telecommunication with
Virginia Electric and Power Company

Virginia Electric and Power Company
(Dominion)

UNITED STATES
NUCLEAR REGULATORY COMMISSION NOTED AUG 2 0 2001 J.E.W.
WASHINGTON, D.C. 20555-0001

August 8, 2001

SERIAL # 01-518

REC'D AUG 2 1 2001

NUCLEAR LICENSING

LICENSEES: Virginia Electric Power Company

FACILITIES: North Anna, Units 1 and 2
Surry, Units 1 and 2

SUBJECT: SUMMARY OF JULY 31, 2001, TELECOMMUNICATION WITH VIRGINIA ELECTRIC POWER COMPANY

On July 31, 2001, the U.S. Nuclear Regulatory Commission (NRC) staff had a conference call with representatives of Virginia Electric Power Company (VEPCO) to discuss information relating the the staff's review of the North Anna and Surry license renewal application review. A list of participants is attached. The information discussed, the applicant's responses, and the follow-up actions are provided below.

NAS and SPS License Renewal Applications, Sections 3.3.1 to 3.3.6, "Auxiliary Systems"

1. The staff requested a clarification as to the results of the applicant's operational history review that led them to manage loss of material on stainless steel components in an air environment (water-ladened or intermittently exposed to water).

   The applicant stated that they have no operating history of aging of stainless steel components in an air environment (water-ladened or intermittently exposed to water), however, they decided to manage these components for potential loss of material to ensure a conservative approach will detect such aging in the period of extended operation.

   The staff found this response acceptable and will not need any additional information relating to this matter.

2. In both LRAs, Tables 3.3.1-1, "Chemical and Volume Control System," and Table 3.3.1-4, "Sampling System," the applicant identifies loss of pre-load as an applicable aging effect for bolting. The applicant credits the ISI Program - Component and Component Support Inspections as the aging management program to manage loss of pre-load in these applications. The staff requested that the applicant provide additional description on how this aging management program will be used to detect loss of pre-load.

   The applicant stated that the intent of this program is to identify gross loss of pre-load (lose bolts) through visual inspections. The program is not intended to detect a reduction in torque.

The staff found this response acceptable and will not need any additional information relating to this matter.

NAS and SPS License Renewal Applications, Section 2.5, "Screening Results: Electrical and Instrumentation and Controls Systems"

1. The staff requested that the applicant explain the exclusion of offsite power systems from the scope of license renewal as required by 10 CFR 54.4(a)(3) with regards to station blackout (10 CFR 54.63).

   The applicant stated that the North Anna and Surry station blackout analysis relied primarily on the recovery of the emergency diesel generators.

   The staff disagreed with the applicant and stated that, for North Anna and Surry, the specified duration for recovery was based on Regulatory Guide 1.155 and NUMARC 87-00 that includes the recovery of offsite power. In addition, 10 CFR 50.63(a) states that the station blackout duration shall be based on "[t]he expected frequency of loss of offsite power" and "[t]he probable time needed to restore offsite power." Based on this information, the staff requires that applicable offsite power structures and components need to be included within the scope of license renewal and subject to an aging management review, or additional justification for its exclusion needs to be provided. The staff will forward a request for additional information as a follow-up to this concern.

2. In both LRAs, Table 2.2-2, the applicant states that the AAC diesel service air system (BSR), is not within the scope of license renewal. The staff requested a clarification as to the function of the AAC diesel service air system, and any support functions regarding the emergency diesel generators (EDG) or any other safety related function.

   The applicant stated that the AAC diesel service air system is primarily used for maintenance purposes and does not provide a support function to the EDG or any other safety related component. The AAC Diesel Starting Air System is the air system that supports the EDG safety related function, and is in the scope of license renewal. Refer to the LRAs, Table 2.2-1.

   The staff found this response acceptable and will not need any additional information relating to this matter.

3. In the NAS LRA, Table 2.2-2, the applicant states that the 4kV System and above (PH) is not within the scope of license renewal. The staff requested a clarification as to the function of the PH systems, and any safety-related or support function(s).

   The applicant stated that the PH System is unique to NAS. Its primary function is to support the main generator output breaker, which is non-safety-related. It has no other safety-related or support function.

The staff found this response acceptable and will not need any additional information relating to this matter.

4. In the SPS LRA, Table 2.2-3, the applicant states that the high level and low level intake structures are within the scope of license renewal. However, in Table 2.2-4 of the SPS LRA, the applicant states that the high level intake structure control house and the low level intake structure switchgear building are not within the scope of license renewal. The staff requested a clarification as to the function of the high level intake structure control house and the low level intake structure switchgear building, and verify that the structures in questions do not have any safety-related or support equipment located within these structures.

   The applicant stated that the high level intake structure control house and the low level intake structure switchgear building are unique to SPS because of its natural circulation service water and circulating water systems. The high level intake structure control house contains such components as the screen drive motors, the screen wash pumps, and hotel loads. The low level intake structure switchgear building primarily houses the switch gear for the 4160 volt, 480 volt, and 120 volt power supplies, switchgear, and transformers to the non-safety-related circulating water systems. It has no other safety-related or support function.

   The staff found this response acceptable and will not need any additional information relating to this matter.

5. In the SPS LRA, Table 2.2-4, the applicant states that the local emergency operating facility is not within the scope of license renewal. The staff requested a clarification as to the function of the local emergency operating facility, and any safety-related or support function(s).

   The applicant stated that the local emergency operating facility was originally built to support an emergency response. These functions have since been transferred to the applicant's headquarters in Richmond, VA and other on-site locations. The only emergency response function of this facility is that it serves as a gathering place for State and local officials during an emergency, as appropriate. This structure has no other safety-related or support function and, therefore, is not within the scope of license renewal.

   The staff found this response acceptable and will not need any additional information relating to this matter.

6. In both LRAs, Section 2.5.2, the applicant states that the evaluation boundaries generally includes all cables and connectors in these areas to provide the complete coverage of cables and connectors in the scope of license renewal. The staff requested a clarification as to the use of the term "generally" in this statement.

The applicant stated that the term "generally" was used because the evaluation boundries included all cables and connectors with the exception of those supplying the control rod drive mechanisms (CRDMs) and the bare grounding conductors. The applicant explained the CRDMs are included within the scope of license renewal because it serves a safety-related pressure boundary function. However, the rod movement function is not safety-related and is not within the scope of license renewal and, therefore, the associated cables and connectors are also not within the scope of license renewal. The bare grounding conductors were found to be outside the scope of license renewal on several past license renewal applications.

The staff will request additional information relating to this concern to more formally document the information provided during this telecommunication.

NAS and SPS License Renewal Applications, Appendix B, Section B2.1.1, "Buried Piping and Valve Inspection Activities"

Scoping

1. The staff requested a clarification if the buried pipe inspection program include periodic inspections when components in the applicable systems are excavated for any reason, and how often does the applicant expect these inspections to take place.

   The applicant stated that the work control program includes the inspection of components when they are excavated. However, both NAS and SPS have not needed excavation of buried component very often in the past. Therefore, the applicant's program will ensure that a sample of each component, based on material and environment, will be excavated at least once prior to the period of extended operation to ensure adequate aging management prior to entering the period of extended operation.

   The staff found this response acceptable and will not need any additional information relating to this matter.

2. In the SPS LRA, page B-9, the applicant identifies copper-nickel as one of the materials for the piping buried on-site. In the LRA, page B-8, copper-nickel is not identified as one of the representative samples of material/buried conditions. The staff requested the applicant to provide a justification for the exclusion of copper-nickel material for the representative sample of materials.

   The applicant stated that the exclusion of copper-nickel as one of the representative samples of materials was an administrative oversight and should have been identified on page B-8.

   The staff found this response acceptable. However, the staff will follow-up with a request for additional information to more formally document this information.

3. The staff requested the applicant to clarify the criteria that will be used to select the representative samples of buried pipes.

The applicant explained that the representative samples for buried pipes will be solely based on material of the buried components and the burial conditions of each component. The applicant also confirmed that there is no significant difference in the soil conditions at the different sites that would make a difference in the aging management activities needed at each site.

The staff found this response acceptable and will not need any additional information relating to this matter.

Detection of Aging Effects

1. The staff requested a clarification as to use of visual inspections that will be used to detect gross indications of changes in material properties for copper-nickel components, what changes in material properties the program is attempting to detect and how this will be accomplished by visual inspections.

   The applicant stated that copper-nickel piping is primarily used underground and in air environments with intermittent wetted conditions in service water lines that connect to chillers that are within the scope of license renewal. The applicant stated that they do not expect to see any changes in material properties (such as selective leaching) in the buried copper-nickel piping, and that the changes in material properties of the service water lines to the chillers will be their lead indication of any potential aging. Because the service water lines to the chillers are available for visual inspections, the applicant will be able to observe any changes in material properties.

   The staff recognizes that certain grades of copper-nickel are susceptible to selective leaching and, therefore, requested that the applicant formally identify the grade of copper-nickel used in buried piping applications on-site to verify that selective leaching is not a concern.

2. In the SPS LRA, the applicant identifies cast iron as one of the materials for the piping buried on-site. Because this material is susceptible to selective leach, the staff requested the applicant to provide a justification for not including hardness measurements as part of its aging management program in determining loss of material properties.

   The applicant stated that the buried piping inspection activities are intended to detect any damage to the protective coating that would allow damage to the buried piping. If damage to the coating is found, the applicant would then take the appropriate steps, including hardness testing when appropriate, to identify any damage to the pipe as a result of the piping being exposed to underground conditions.

   The staff found this response acceptable and will not need any additional information relating to this matter.

3. In the NAS LRA, the applicant states that some of the buried piping uses cathodic protection. The staff recognizes that monitoring cathodic current is a good means of identifying potential damage to coating material of buried components and questioned the applicant, as to why they did not take advantage of this indication in its aging management activities.

   The applicant explained that its current aging management activities are adequate as described in the LRA. However, they stated that they do monitor cathodic protection current along with pipe-to-soil potential current as a means of identifying degradation of buried component coating but do not take credit for these activities as aging management activities.

   The staff found this response acceptable and will not need any additional information relating to this matter.

Operating Experience

In both LRAs, the applicant states that significant degradation of buried piping has not been found at either site. This statement is based on the experience that has been gained through the Work Control Process with respect to buried fire protection piping (all four units) and service water system piping (NAS 1 and2). In order to assess the significance of the operating experience, the staff requested the applicant to describe how many sample opportunities of buried piping and valves have occurred over the life of the buried pipe within the scope of license renewal and correlate the inspections performed with the material/burial condition combinations identified under the scope section of this AMP.

The applicant identified the service water system, fuel oil systems, and the fire protection systems as the systems that are within the scope of license renewal that contain buried components subject to an AMR. The applicant stated that a review of their operating experience for each of these systems did not identify any failure of buried components due to aging or failure of coating material.

The staff found this response acceptable. However, the staff will follow-up with a request for additional information to more formally document this operating experience.

Draft Generic RAIs Regarding Seismic II/I Piping Systems and Other Related SSCs That Meet 10 CFR 54.4(a)(2) Scoping Criterion

Attached for your information are generic RAIs relating to Seismic II/I and other related SSCs (Attachment 2). These RAIs are not being asked of you, but identify the basic information needed in a LRA relating to the SSCs in questions, and its AMR. The staff is reviewing your LRA, and will follow-up with any appropriate RAIs needed for the staff to complete its evaluation.

A draft of this telephone conversation summary was provided to VEPCO to allow them the opportunity to comment on the contents of its input prior to the summary being issued.

Robert J. Prato, Project Manager
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Office of Nuclear Reactor Regulation

Docket Nos. 50-338, 50-339, 50-280, and 50-281

Attachments: As stated

cc w/att: See next page

Attendance list
Telephone Conference Call Virginia Electric Power Company (VEPCO)
July 31, 2001

Name	Organization
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Jame Lazevnick	NRC/NRR
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Meena Khanna	NRC/NRR
Robert Prato	NRC/NRR
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Julius [Lucky] Wroniewicz	VEPCO
Tom Snow	VEPCO
Ben Rodill	VEPCO

Draft Generic RAIs Regarding Seismic II/I Piping Systems and Other Related SSCs

10 CFR 54.4(a)(2) - Scoping

RAI #1 An applicant for license renewal should consider two configurations of non-safety-related piping systems that could potentially meet the 54.4(a)(2) scoping criterion. The first configuration includes non-safety-related piping systems (including piping segments and supports) which are connected to safety-related piping. These non-safety-related piping systems should be included within the scope of license renewal up to and including the first seismic support past the safety-related/non-safety-related interface. The second configuration involves non-safety-related piping systems which are not connected to safety-related piping, but have a spatial relationship such that their failure could adversely impact on the performance of an intended safety function. For this piping system configuration, the applicant has two options when performing its scoping evaluation; a mitigative option or a preventive option. With the mitigative option, the applicant must demonstrate that plant mitigative features (e.g., pipe whip restraints, jet impingement shields, spray and drip shields, seismic supports, flood barriers, etc.) are provided, which are provided to protect safety-related SSCs from a failure of non-safety-related piping segments. When evaluating the failure modes of non-safety-related piping segments and the associated consequences, age-related degradation must be considered. The staff notes that pipe failure evaluations typically do not consider age-related degradation when determining pipe failure locations. Rather, pipe failure locations are normally postulated based on high stress. Industry operating experience has shown that age-related pipe failures can, and do, occur at locations other than the high-stress locations postulated in most pipe failure analyses. Therefore, to utilize the mitigative option, an applicant should demonstrate that the mitigating devices are adequate to protect safety-related SSCs from failures of non-safety-related piping segments at any location where age-related degradation is plausible. If this level of protection can be demonstrated, then only the mitigative features need to be included within the scope of license renewal, and the piping segments need not be included within the scope. However, if an applicant cannot demonstrate that the mitigative features are adequate to protect safety-related SSCs from the consequences of non-safety-related pipe failures, then the applicant should utilize the preventive option, which requires that the entire non-safety-related piping system be brought into the scope of license renewal and an AMR be performed on the components within the piping system. Finally, an applicant may determine that in order to ensure adequate protection of the safety-related SSC, a combination of mitigative features and non-safety-related SSCs must be brought within scope. Again, it is incumbent upon the applicant to provide adequate justification for the approach taken with respect to scoping of non-safety-related SSCs in accordance with the Rule.

To determine if all SSCs which meet the 54.4(a)(2) scoping criterion have been included within the scope of license renewal, the staff requests that the applicant identify the following:

a. Whether non-safety-related piping that is connected to safety-related piping is within the scope of license renewal, up to the first seismic support past the safety-related/non-safety-related interface. If not, please provide the basis for not including this piping within scope.

b. Whether the mitigative option, the preventive option, or a combination, is used for non-safety-related piping systems which are not connected to safety-related piping, but have a spatial relationship such that their failure could adversely impact on the performance of an intended safety function. For each non-safety-related piping system which would normally be included within the scope of license renewal, but is excluded because mitigative features have been credited for protecting safety-related SSCs from the failure of the non-safety-related piping system, please identify

   1. the mitigative feature(s) that is credited for protection,
   2. the hazard (e.g., failure mechanisms and postulated failure locations) for which the mitigative feature(s) is providing protection, and
   3. a summary discussion (including references, such as reports, analyses, calculations, etc.) of the basis for the conclusion that the mitigative feature(s) is adequate to protect safety-related SSCs.

   The staff will review the information to determine whether the mitigative features are adequate for protecting safety-related SSCs from aging-related failures of non-safety-related piping systems.

RAI #2 Given the methodology used to identify piping systems that meet the 54.4(a)(2) scoping criterion, the staff is concerned that there may be other non-safety-related mechanical or structural components which would normally be included within the scope of license renewal, but are excluded because mitigative features have been credited for protecting safety-related SSCs from the failure of the non-safety-related mechanical or structural component. If such credit is being taken, please identify these non-safety-related mechanical or structural components and indicate:

a. the mitigative feature(s) that is credited for protection,
b. the hazard (e.g., failure mechanisms and postulated failure locations) for which the mitigative feature(s) is providing protection, and
c. a summary discussion (including references, such as reports, analyses, calculations, etc.) of the basis for the conclusion that the mitigative feature(s) is adequate to protect safety-related SSCs.

The staff will review the information to determine whether the mitigative features are adequate for protecting safety-related SSCs from the aging-related failures of non-safety-related mechanical and structural components.

<u>10 CFR 54.4(a)(2) - Aging Management Review</u>

RAI #1 An applicant for license renewal should consider two configurations of non-safety-related piping systems that could potentially meet the 54.4(a)(2) scoping criterion. The first configuration includes non-safety-related piping systems (including piping segments and supports) which are connected to safety-related piping. These non-safety-related piping systems should be included within the scope of license renewal up to and including the first seismic support past the safety-related/non-safety-related interface. In addition, aging management of these non-safety-related piping segments should be the same as for the safety-related piping to which it is connected. Please confirm that the same aging management programs and activities used to manage aging of safety-related piping will be used to manage the connected non-safety-related piping, up to the first seismic support past the safety-related/non-safety-related interface. If the non-safety-related piping will be managed different from the connected safety-related piping, please provide a basis for managing it differently.

RAI#2 The second configuration involves non-safety-related piping systems which are not connected to safety-related piping, but have a spatial relationship such that their failure could adversely impact on the performance of an intended safety function. For these piping systems that are within the scope of license renewal, please provide information regarding how these piping systems will be managed to mitigate or reduce age-related degradation. The response should identify all aging management programs and other activities which will be credited for managing the aging effects associated with these piping systems.

RAI#3 For other non-safety-related mechanical and structural components which meet the 54.4(a)(2) scoping criterion, and are within the scope of license renewal, please provide information regarding how these mechanical and structural components will be managed to mitigate or reduce age-related degradation. The response should identify all aging management programs and other activities which will be credited for managing the aging effects associated with these mechanical and structural components.

Virginia Electric and Power Company

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Attachment 2

License Renewal – Review of NRC Letters
Serial No. 02-277

NRC Letter dated October 11, 2001

Summary of August 8, 9, 13, 27, and 28, 2001 Telecommunication with Virginia Electric and Power Company

Virginia Electric and Power Company
(Dominion)

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

October 11, 2001

SERIAL # 01-659

RECD OCT 25 2001

NUCLEAR LICENSING

LICENSEES: Virginia Electric Power Company

FACILITIES: North Anna, Units 1 and 2
Surry, Units 1 and 2

SUBJECT: SUMMARY OF AUGUST 8, 9, 13, 27, and 28, 2001, TELECOMMUNICATION WITH VIRGINIA ELECTRIC AND POWER COMPANY

On August 8, 9, 13, 27, and 28, 2001, the U.S. Nuclear Regulatory Commission (NRC) staff had conference calls with representatives of Virginia Electric and Power Company (Dominion) to discuss information relating the staff's review of the North Anna, Units 1 and 2 (NAS 1 and 2), and Surry, Units 1 and 2 (SPS 1 and 2) license renewal applications (LRAs) review. A list of participants is attached. The information discussed, the applicant's responses, and the follow-up actions are provided below.

Section 2, "Scoping"

Item 2-1 In both LRA, the applicant references the drawings provided with the applicant and notes that the highlighted portions of those drawings are the portions of the systems that are within the scope of license renewal. Each drawing contains a legend that indicates that the highlighted portions represent those portions of the systems that are subject to an aging management review (AMR). Please clarify that the highlighted portion of the drawings represent the portion of the systems that are within the scope of license renewal.

The applicant confirmed that the highlighted portions of the drawings represent those portions of the systems that are within the scope of license renewal, and that some of the highlighted structures and components may not be subject to an AMR because they are short-lived.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Section 2.3.3.7, "Service Water"

Item 2.3.3.7-1 SPS may occasionally use a temporary service water (SW) flow path to perform maintenance on the single SW supply to the component cooling water heat exchangers. The SPS update Final Safety Analysis Report (UFSAR) indicates that this temporary flow path piping is routed through the turbine building basement from the circulating water inlet piping to the supply piping of two of the component cooling heat exchangers. The UFSAR also indicates that the temporary flow path must be used in accordance with an approved temporary change to the Technical Specifications and an associated license condition, and is used only during a Unit 1 outage. Given the importance of maintaining SW flow to Unit 2 while operating, as well as Unit 1 loads while shut down, will the temporary flow path piping receive AMR?

The applicant stated that the temporary flow path piping is not within the scope of license renewal. The piping of concern is part of a temporary modification that is submitted to, and reviewed by, the staff as a technical specification exception to allow the applicant to operate outside of normal plant design and operational configurations to perform special maintenance activities.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item 2.3.3.7-2 The SPS SW system is supplied by the circulating water (CW) system. Intake canal water inventory is maintained during plant operation by up to four CW pumps per unit that take a suction from the James River at the low-level intake structure and discharge through large-bore pipes to the higher elevation intake canal. Anti-siphoning standpipes are provided on the pump discharge pipes to prevent draining the intake canal in the event of backflow through these lines. The SPS UFSAR indicates that this anti-siphon function is provided by active (air-operated) vacuum breakers. The stand pipes are also equipped with passive vacuum breakers to provide the important anti-siphoning function in the event of failure of the active vacuum breakers. It was not evident from the information provided in the application whether the passive vacuum breakers will receive an AMR. Will these vacuum breakers receive an AMR?

The applicant stated that the anti-siphoning device/passive vacuum breakers are simply holes in the piping set at a specific elevation to ensure that the siphoning effect will not drain the intake canal below a certain level. Because the potential loss of material is the only applicable aging effect, and an increase in the size of the hole will not affect the intended function, no aging management is needed.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item 2.3.3.16-1 The air tanks of the NAS compressed air (CA) system are highlighted on the appropriate license renewal drawings, but are not listed as a component group on Table 2.3.3-13. The applicant may need to list these components in Table 2.3.3-13 to ensure they receive AMR.

The applicant noted that the air tanks are in the scope of license renewal, but not subject to an AMR because they are short-lived. The tanks in question are cylinders that are replace every 10 years as prescribed by a site required preventive maintenance activity.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Sections 3.1.1, "Reactor Coolant System Piping and Associated Components"

Item 3.1.1.2-1 Section 3.1 of topical report WCAP-14575-A, "Aging Management Evaluation for Class 1 Piping and Associated Pressure Boundary Components," discusses industry issues associated with the reactor coolant systems (RCS) piping components. Renewal applicant action item number 3 from the staff's final safety evaluation report (SER) states that "[t]he renewal applicant should complete the updated review of generic communications and capture any additional items not identified by the original review." The original review includes published documents up to 1994. In response to the renewal applicant action item, the applicant states that it has completed a review of all generic communications relating to the RCS components. Discuss the criteria used to determine which issues in the generic communications required an AMR.

The applicant agreed to provide the criteria used to determine which issues in the generic communications required an AMR.

The staff will provide a request for additional (RAI) requesting that the applicant provide additional information regarding the criteria used to determine which issues in the generic communications required an AMR.

Item 3.1.1.2-2 Renewal applicant action item number 6 from the staff's final SER for WCAP-14575-A states that "[t]he license renewal applicant should perform additional inspection of small-bore RC system piping, that is, less than 4-inch-size piping, for license renewal to provide assurance that potential cracking of small-bore piping is adequately managed during the period of extended operation." In response to the renewal applicant action item, the applicant stated that selected volumetric examinations are being performed on SPS Unit 1 on a sample population of welds in several 3-inch lines in the safety injection (SI) and chemical and volume control systems (CVCS). The SI and CVCS lines are Class 2 piping; however, they are used as leading indicators for small-bore piping conditions in Class 1 systems. Provide justification for the conclusion that the SI and CVCS small-bore lines bound all small-bore lines within the scope of license renewal for the RCS piping.

The applicant agreed to provide the justification for the conclusion that the SI and CVCS small-bore lines bound all small-bore lines within the scope of license renewal for the RC piping system.

The staff will provide an RAI requesting that the applicant provide the justification for the conclusion that the SI and CVCS small-bore lines bound all small-bore lines within the scope of license renewal for the RCS piping.

Item 3.1.1.2.1-1 WCAP-14575 A identified wear of closures as an aging effect that requires an AMR. In both LRAs, Section 3.1.1, the applicant states that "[i]n the AMR results of the reactor coolant system presented in this section, wear will not result in an aging effect requiring management." A discussion on the treatment of wear is presented in Appendix C, Section C3.1.7 of the LRA. Provide the basis for concluding that wear in RC piping and associated components is not an aging effect requiring management for NAS and SPS.

The applicant explained that WCAP-14575 refers to wear as an aging mechanism for the loss of material as it applies to reactor coolant pumps (RCPs) and Class 1 valve closure parts such as covers, flanges, and closure bolting that can be exposed to some degree of relative motion if preload is lost. Although NAS and SPS have no operating history of "wear" in the areas of concern (as an aging mechanism or aging effect), the applicant does manage for the loss of material in all RCS piping, valve bodies, and pump casings that are within the scope of license renewal, including associated flanges, covers, and bolting.

The staff found the applicant's response acceptable, and will not need any additional information regarding this matter.

Item 3.1.1.2.2-1 In both LRA, Table 3.1.1-1, the applicant identifies the inservice inspection (ISI) program as an aging management activity for cracking in piping and valve bodies. The footnotes in Table 3.1.1-1 indicates that ISI, as an aging management activity, is applicable to Class 1 components only. If there are any Class 2 piping or valve bodies that are within the scope of license renewal for RCS piping and associated components, discuss how cracking will be managed during the period of extended operation.

The applicant agreed to provide a additional information regarding cracking as an applicable aging effect for RCS Class 2 piping and associated components that are within the scope of license renewal.

The staff will provide an RAI requesting that the applicant provide the additional information regarding the aging of RCS Class 2 piping and associated components.

Sections 3.1.2, "Reactor Vessel"

Item 3.1.2.2.2-1 In both LRAs, Section B2.2.13 of Appendix B, the ISI program - reactor vessel aging management activities (AMA), the applicant identifies two additional inspections that are included in the augmented inspection activities in Section B2.2.1, "Augmented Inspection Activities" of the LRA. The additional inspections are primarily enhanced ASME Section XI inspections and include the incore flux thimble tubes in the RV bottom and the control rod drive housings on the upper head. Clarify why the augmented inspection activities AMA in Section B2.2.1 of the LRA is not included as one of the applicable AMAs the reactor vessel. In addition, discuss the associated aging management for the emerging issue regarding the cracking of control rod drive tubing.

The applicant explained that the associated Chapter 3 tables have hyper-links to the "Inservice Inspection Programs - Reactor Vessel," in Appendix B of the LRAs. From Inservice Inspection Programs - Reactor Vessel in Appendix B, there are hyper-links to the augmented inspection activities, as appropriate. Therefore, the related augmented inspection activities are used to manage Reactor Vessel aging.

With respect to the circumferential cracking of control rod drive tube cracking, the applicant explained that they intend to embrace the solution agreed upon by the staff under 10 CFR Part 50; and agreed to carry that solution forward, as applicable, as an aging management program for the purpose of license renewal.

The staff found the applicant's response acceptable, and will review the use of augmented inspections to ensure adequate aging management. If the staff's evaluation determines that sufficient aging management of the Reactor Vessel is identified through the use of Inservice Inspection - Reactor Vessel and augmented inspections, no additional information regarding this matter will be needed. Otherwise, the staff will provide an RAI requesting the additional information regarding this concern. In the end, the staff found the applicant's response acceptable and will not need any additional information regarding the cracking of control rod drive tubes.

Section 3.1.3, "Reactor Vessel Internals"

Item 3.1.3.2-1 In both LRAs, Table 3.1.3-W1, the applicant provides responses to topical report WCAP-14577, "License Renewal Evaluation: Aging Management for Reactor Internals," Applicant Action Items. The applicant's response to item 1 indicates that the Dominion reactor vessel internals are bounded by the topical report. The response also indicated that the programs necessary to manage the effects of aging are identified in the LRAs, Table 3.1.3-1. However, Table 3.1.3-1 of the LRA does not address the effects of wear that are addressed in AMP-4.3 of WCAP-14577. Explain how wear in thimble tubes and other RVI components (i.e. interfaces of components which have relative motion) will be managed for the period of extended operation.

The applicant explained that in both LRAs, Section 3.1.3, the thimble tube is evaluated as part of the reactor vessel and not the reactor vessel internals and, therefore, is included in the reactor vessel AMR. In both LRA, Appendix C, the applicant defines wear as an aging mechanism for the loss of material consistent with the WCAP characterization of wear. The applicant noted that Table 3.1.2-1 does identify loss of material as an applicable aging effect for the thimble tubes that is managed by ISI Program- Reactor Vessel. The applicant also noted that Table 3.1.3-1 does identify loss of material for sub-components of the RV Internals that is managed by the reactor vessel internals inspection program for those that could be subject to wear.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item 3.1.3.2-2 Section 2.6.7.2 of topical report WCAP-14577, Rev. 1-A, states that the guide tube support pins have experienced stress corrosion cracking (SCC). The support pin degradation issue has been addressed for Westinghouse plants on a plant-specific basis either by a complete replacement of support pins, or through inspections that demonstrate no degradation. As noted in the topical report, SPS, Unit 2, has not upgraded to the new material, and SPS, Unit 1, has a different support pin design which is excluded from the topical report. Discuss support pin design differences and the program in place at SPS 1 and 2 to detect and manage SCC in guide tube support pins.

For SPS, Unit 1, the support pin is the Framatone design that uses an interference fit compressive design to perform its intended function. The Unit 2 support pin is the original design, which uses a pre-stressed tensile design to perform its intended function. As indicated in Table 3.1.3-1, the guide tube support pin is listed as the control rod guide tube split pins, and is managed by the chemistry control program and the RVI inspection activities.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item 3.1.3.2-3 Renewal Applicant Action Item 6 in the final SER for WCAP-14577 states that the applicant must describe its aging management plans for loss of fracture toughness in cast austenitic stainless steel (CASS) RVI components, considering the synergistic effects of thermal aging and neutron irradiation embrittlement in reducing the fracture toughness of these components. Provide the neutron fluence for the CASS RVI components for the period of extended operation, and describe the aging management plan for the CASS components, considering the synergistic effects of thermal aging and neutron irradiation embrittlement.

With respect to the synergistic effects of thermal aging and neutron embrittlement on CASS RVI components, the applicant credited the RVI inspection activities as its aging management program for loss of fracture toughness. The applicant also identified a follow-up action item to monitor industry initiatives under the EPRI "Materials Reliability Program" (MRP). The applicant will implement the NRC-approved industry activities resulting from the MRP, as appropriate, to manage any applicable aging effects identified through the EPRI MRP effort.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item 3.1.3.2-4 Renewal Applicant Action Item 9 in the final SER for WCAP-14577 states that the applicant must address plant-specific plans for managing cracking (and loss of fracture toughness) of RVI components, including any plans for augmented inspection activities. The final SER also states that detection of relevant conditions from the VT-3 visual examination required by Examination Category B-N-3 of the ASME Code may not be adequate to detect cracking of the susceptible RVI components. Provide the basis for not including augmented inspection activities to manage cracking (and loss of fracture toughness)of RVI components. In addition, describe what supplemental examinations will be performed if relevant conditions are detected.

With respect to the RVI components, the applicant credited the RVI VT-3 inspection activities as its aging management program for cracking. The applicant also identified a follow-up action item to monitor industry initiatives under the EPRI MRP. The applicant will implement the NRC approved industry activities resulting from the MRP, as appropriate, to manage any applicable aging effects identified through the EPRI MRP effort.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item 3.1.3.2-5 Renewal Applicant Action Item 10 in the final SER for WCAP-14577 states that the applicant must address plant-specific plans for management of age-related degradation of baffle/former and barrel/former bolting, including any plans for augmented inspection activities. WCAP-14577, Rev. 1-A acknowledges, and the staff agrees, that VT-3 examinations alone will not detect cracking in baffle/former and barrel/former bolting. Augmented inspections, such as ultrasonic inspections, are proposed in the final SER to provide effective management of aging effects. Provide the basis for not including augmented inspection activities for the baffle/former and barrel/former bolting, and describe the proposed inspection for the baffle/former and barrel/former bolting that will ensure management of age-related degradation for the period of extended operation.

With respect to the baffle/former and barrel/former bolting, the applicant credited the RVI VT-3 inspection activities as its aging management program for cracking. The applicant has also identified a follow-up action item to monitor industry initiatives under the EPRI MRP. The applicant will implement the NRC-approved industry activities resulting from the MRP, as appropriate, to manage any applicable aging effects identified through the EPRI MRP effort.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item 3.1.3.2.1-1 The final SER for WCAP-14577 includes additional aging mechanisms that were not considered by the applicant in the LRA. Provide justification for concluding that the following aging mechanisms are not applicable to the NAS and SPS RVI components:

a. In Section 3.2.1 of the final SER, the staff did not agree that 1 x 10^{21} n/cm^2 (E>0.1MeV) should be the threshold fluence for screening RVI components. However, the staff concluded that the AMP proposed in WCAP-14577 addressed the components with the highest fluences, so the threshold fluence approach did not affect the results of the review. In Section C3.5.2 of the LRA, the applicant states that neutron embrittlement of RVI components has been evaluated during the AMRs., however, no specific information was provided in the LRA regarding this evaluation for RVI components. Provide the results of the AMR review for neutron embrittlement of RVI components.

In both LRAs, Appendix C, Section C.3.5.2, the applicant defines neutron embrittlement as a loss of fracture toughness and, therefore, Table 3.1.3-1 identifies the appropriate RVI components that are subject to loss of fracture toughness and the appropriate AMA needed to manage this aging. The applicant also identified the lower support plate, although not listed (as a result of an administrative error), as susceptible to neutron embrittlement. The applicant stated that the RVI inspection activities is the AMA used to manage loss of fracture toughness for this component.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

b. Section 3.2.5 of the final SER states that creep is not a concern for stainless steel alloys and nickel-based alloys under pressurized-water reactors conditions with temperatures below 1000 °F. WCAP-14577 indicates that creep can be caused by defects that result from neutron flux exposure, and the staff concurred with this conclusion. The applicant did not address the possibility of creep in the LRA. Provide justification as to why creep caused by defects, that result from neutron flux exposure, is not applicable to NAS and SPS.

In both LRAs, Appendix C, Section C.3.4.1, the applicant describes creep as an aging mechanism for stress relaxation and, therefore, subject to loss of preload. Table 3.1.3-1 identifies the baffle/former and barrel/former bolting as being subject to loss of preload and the ISI-component and component support inspection activities as the appropriate AMA needed to manage this aging.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item 3.1.3.2.1-2 WCAP-14577, Rev. 1-A, Tables 4-2, 4-3, 4-5, and 4-6 address specific surveillance techniques, frequencies, and acceptance criteria for irradiation-assisted stress-corrosion cracking (IASCC), stress relaxation, wear, and fatigue of RVI components, respectively. Tables 4-7 and 4-8 identify the AMA attributes for the baffle/former and barrel/former bolts. The applicant did not include the loose parts monitoring and neutron noise monitoring surveillance techniques, which are listed in WCAP-14577 for managing aging effects of the RVI components. Provide justification for not including the above mentioned surveillance techniques to manage RVI aging effects.

The applicant stated that it took exception to WCAP-14577 regarding the use of loose parts monitoring and neutron noise monitoring surveillance techniques for managing irradiation-assisted stress-corrosion cracking, stress relaxation, wear, and fatigue of RVI components. The applicant further stated that it relied on the rigor of its RVI inspection activities. The applicant has also identified a follow-up action item to monitor industry initiatives under the EPRI MRP. The applicant will implement the NRC approved industry activities resulting from the MRP, as appropriate, to manage any applicable aging effects identified through the EPRI MRP effort.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Section 3.1.4, "Pressurizer"

Item 3.1.4.2-1 In both LRA, the applicant references WCAP-14574-A, "Aging Management Evaluation for Pressurizers," the Westinghouse pressurizer topical report. In the staff's safety evaluation for WCAP-14574-A, under Renewal Applicant Action Item 4, the staff addresses the ability of pressurizer bolting to withstand stress corrosion cracking. The staff stated that for the applicant to take credit for the criteria given in EPRI Report NP-5769, the applicant needs to state that the acceptable yield strengths for the quenched and tempered low-alloy steel bolting materials (e.g., SA-193 Grade B7, materials) are in the range of 105-150 ksi. In its LRA, Appendix C, Section C3.2.1, the applicant states that the measured yield strengths of the bolting described in this appendix were all found to be less than 150 ksi; however, there is no mention of meeting the lower bound of 105 ksi. To ensure that the yield strengths for SA-193, Grade B7, materials are appropriately controlled, discuss the procedures, programs, practices, or activities at your facilities, which ensure that the yield strengths for the materials have been procured within the minimum value required for SA-193, Grade B7, materials (i.e., to ensure that the yields strengths are above 105 ksi).

The applicant clarified that all applicable Grade B7 materials were purchased in accordance with the requirements of SA-193 under its 10 CFR Part 50, Appendix B, procurement program.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Section 3.2, "Aging Management of Engineered Safety Feature Systems"

Item 3.2.2-1 Clarify either by reference to appropriate information in the LRA, or by discussion as to why loss of material is the only applicable aging effect for some non-CASS stainless steel engineered safety feature (ESF) components that are exposed to treated water, whereas cracking is added to loss of material as an additional aging effect for other non-CASS stainless steel ESF components that are exposed to the same environment.

The applicant referred to Appendix C, Section C3.2.1 and C3.2.2 of its LRAs. The applicant explained that the piping in question is maintained below 140 °F to eliminate SCC as a concern. The piping in questions is outside of the ASME Class 1 boundary such that flaw initiation and growth is not a concern. Therefore, cracking is not an applicable aging effect for some stainless steel components in treated water.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item 3.2.2-2 In both LRAs, the applicant identifies five different types of carbon or low alloy steel ESF components that have the potential to be exposed externally to borated water leakage and degraded by loss of material: tanks, bolting, piping, coolers and the SI accumulators. For the tanks and the FC bolting the applicant propose to use the general condition monitoring activities to manage this effect. For piping and most of the remaining ESF bolting, the applicant identifies both the boric acid corrosion surveillance program and the general condition monitoring activities to manage the applicable aging. For the coolers and SI accumulators the applicant identifies the boric acid corrosion surveillance program to manage the applicable aging. Clarify either by reference to appropriate information in the LRAs, or by discussion as to why the programs or activities selected to manage loss of material as a result of borated water leakage differs for these carbon or low-alloy steel components.

In both LRAs, Appendix B, Section B2.2.3 and B2.2.9, the applicant identifies the components outside of containment as being managed by the general condition monitoring activities and the components inside containment as being managed by the boric acid corrosion surveillance activities.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item 3.2.2-3 In both LRAs, the applicant identified the ISI Program - Component and Component Support Inspections as an added program for managing loss of pre-load in bolting, cracking in stainless steel piping, or reduction of fracture toughness in CASS valves that are categorized as ASME Code Class 1. The applicant did not credit these inspection activities as an additional program for managing loss of pre-load in ESF bolting, piping and valves that are categorized as ASME Code Class 2 or 3. Confirm that all ISIs or ISTs on ASME Code Class 1, 2, or 3 ESF components that are currently required by the CLB (i.e., as required under 10 CFR 50.55a and hence by reference to Section XI of the ASME Boiler and Pressure Vessel Code, or by Technical Specifications) will continue to be performed during the period of extended operation regardless of whether the ISI/IST programs, as appropriate, are being credited as the AMP(s) for managing the applicable aging effects for these components.

The applicant explained that it is required, under 10 CFR 50.55a, to perform all ISI and IST on ASME Code Class 1, 2 or 3 ESF components that are currently required by its CLB, and will continue to meet all applicable regulatory requirements during the periods of extended operation,

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item 3.2.2-4 In both LRAs, the applicant states that it will use the work control process to manage loss of material in those stainless steel ESF structures and components that are exposed externally to dry air and internally to treated water. In contrast, the applicant stated that it will use the tank inspection activities and the chemistry control program for primary systems to manage loss of material in stainless steel ESF tanks that are exposed to atmosphere/weather conditions and internally to treated water environments. Clarify either by reference to appropriate information, sections in the applications, or by discussion as to why the programs and activities were selected to manage loss of material in these tanks differs.

The applicant referenced Section B2.1.3 of the LRA and explained that, in general, the tank inspection activities are used to manage aging of large tanks (large enough to enter for inspection), either above ground or below ground, and the work control process is used to manage aging of small tanks, such as the seal water head tanks (which are not large enough to entering for inspection).

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Sections 3.3.9, "Fire Protection and Supporting Systems"

Item 3.3.9-1 In both LRAs, Table 3.3.9, as well as Tables 3.3.7 and Table 3.3.8, the applicant did not identify the aging effects or aging management programs for carbon steel and low-alloy steel components in an external air environment. The staff believes that air may cause corrosion to the external surfaces of carbon steel components. Clarify your position on the potential aging of carbon steel components in an air environment.

The applicant referred to Table 3.0-2 in both LRAs, which better describes the different environments discussed in its AMR. The applicant noted that the air environments referred to in Tables 3.3.7, 3.3.8, and 3.3.9 are all sheltered, non wetted air environments, which would not lead to loss of material.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Section 3.5, "Aging Management of Structures and Component Supports"

Item 3.5-1 In both LRAs, Section 3.5.1, the information provided states that porous concrete is used under the base mat to provide drainage for the containment structure, and that the use of Type II, low-alkali, portland cement (not calcium aluminate cement) in the porous concrete prevents any erosion of concrete and minimizes settlement. The staff notes that this issue has been discussed in IN 98-26, which proposes Maintenance Rule Structures Monitoring to manage this aging effect. In addition, if a de-watering system is relied upon for control of erosion of cement from porous concrete subfoundations and/or relied on to control settlement, the applicant is to ensure proper functioning of the de-watering system throughout the period of extended operation. Therefore, the staff requests that the applicant provide the following information:

a. Provide the technical basis for determining that the use of TYPE II, low-alkali, portland cement as a justification to eliminate the need for managing erosion of porous concrete sub-foundations. Refer to IN 98-26.

The applicant explained that the existing geological conditions and foundation design are not conducive to groundwater conditions that can cause erosion. The applicant also described information provided to the NRC in 1996, in response to a request regarding porous concrete installations, which showed minimal leachate at both SPS and NAS. In addition, the applicant states that results of containment settlement monitoring showed settlement significantly less that design limits and, therefore, determined that aging management is not needed for erosion or settlement.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

b. State whether there is (or is not) a de-watering system at the plants. If so, identify if the de-watering system is relied on to control erosion of the porous concrete sub-foundation and/or control settlement. Explain how the proper functioning of the de-watering system will be ensured throughout the period of extended operation. This request applies to all plant structures (including containment, auxiliary building structure, other Class I structures, and fuel building) whose base mat/foundation utilizes a porous concrete sub-foundation.

The applicant explained that the containments are the only structure with a porous concrete sub-foundation at either facility. The containments at each site were designed with subsurface foundation sump systems. At SPS, the purpose of the sumpthe purpose of the sump system is to remove any minor seepage from inside the waterproof membrane. The intended functions of the sump systems is not to control erosion of porous concrete or settlement of containment. Each of the sump systems were evaluated under 10 CFR 54.4 and determined not to be within the scope of license renewal.

Upon further evaluation, the applicant stated that the purpose of the sump system at SPS is to maintain the ground water level in the cofferdam area around the containment foundation low enough to prevent any minor seepage through the waterproof membrane from rising to the level of the containment liner plate. At NAS the only applicable intended function of the Containment sump system is to limit hydrostatic pressure to prevent swelling of the containment liner plate. Although the sump system is a secondary means (to the waterproof membrane) for preventing the buildup of hydrostatic pressure, this intended function requires the sump system to be included within the scope of license renewal and, therefore, subject to an AMR. The applicant recognizes the need to demonstrate that the buildup of hydrostatic pressure cannot affect the intended function of the containment liner plate, or to provide an aging management program for the SCs of the sump system.

The applicant also identify only one dewatering system that is used to control settlement of structures at either site. The applicant identified the passive horizontal drain system beneath the North Anna service water pump house as the only dewatering system used to control settlement. Monitoring settlement in the area of the NAS service water pump house is a Technical Specification requirement, which requires the plant to be shut down immediately settlement or differential settlement exceed predetermined values. These values are set such that the plant can be brought to, and maintained at, a safe shutdown condition long before the intended function is lost and, therefore, eliminating the need for aging management of the passive drain system.

The staff will provide an RAI requesting that the applicant provide an aging management program for the containment sump system, or provide a technical justification for not managing the effects of aging associated with the containment sump system.

Item 3.5-2 In both LRAs, Section 3.5.1, the information provided states that the structures and structural members located below the local groundwater elevation are not exposed to aggressive chemicals on the basis of recent chemical analyses of the groundwater described in Appendix C. The results of the recent groundwater analyses, presented in Appendix C were reviewed by the staff. The pH level, chloride content, and sulfate content demonstrate that the groundwater is not aggressive. Consequently, the staff concurs that loss of material, cracking, and change in material properties due to aggressive chemical attack are not significant for below grade exterior concrete regions. In addition, loss of material due to corrosion of embedded steel and cracking due to corrosion of embedded steel for below grade exterior regions are not significant. However, the technical basis for ensuring that the groundwater remains non-aggressive in the future and the technical basis for not managing the aging effects listed above for interior and above-grade exterior concrete regions have not been provided. Therefore, the staff requests that the applicant provide the following information:

a. What method, such as periodic monitoring of below-grade water chemistry (including seasonal variations), will be used to ensure that the groundwater remains non-aggressive throughout the period of extended operation

   The applicant stated that it periodically samples the groundwater for aggressive chemicals, but does not think that it is necessary to include periodic sampling as part of its AMP because there is no history of aggressive groundwater over the life of either facility, and no reason to believe that these conditions will change.

   The staff believes that the aggressive state of groundwater can change at almost any location and, to provide reasonable assurance that the effects of aging associated with aggressive groundwater will be managed during the period of extended operation, an applicant needs to periodically verify that groundwater conditions have not changed or provide a technical justification as to why the applicant believes that the groundwater conditions will not change. The staff will provide an RAI requesting the additional information regarding this concern.

b. Identify where in the LRA is the AMR for managing aging of interior and above-grade exterior regions, or provide a technical justification for not managing loss of material, cracking, and change in material properties due to aggressive chemical attack for interior and above grade exterior regions.

   The applicant states that its AMR determined that there were no applicable aging effects for interior, above-grade exterior concrete with the exception of the SPS intake structures, which is being managed.

   The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

c. Identify where in the LRA is the AMR for managing aging of embedded steel, or provide a technical justification for not managing loss of material and cracking due to corrosion of embedded steel for interior and above grade exterior regions. This request applies to all plant structures that contain concrete structural members located below the local groundwater elevation or if an aggressive environment potentially exists for interior or above-grade exterior concrete.

The applicant stated that its AMR determined that interior embedded steel that can be exposed to an aggressive environment is limited to being exposed to boric acid leakage and is managed by the boric acid wastage program inside containment and general condition monitoring outside of containment.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item 3.5-3 In both LRAs, Section 3.5.1 and Appendix C, the information provided indicates that some concrete aging effects are not applicable to NAS 1 and 2, and SPS 1and 2. However, there is no discussion in the LRA to explain why loss of material and cracking due to freeze-thaw is not applicable. In order for the staff to make a determination that all applicable aging effects are being managed, additional information is needed. Therefore, the staff requests that the applicant provide a technical justification as to why loss of material and cracking due to freeze-thaw is not an applicable aging effect for concrete components at NAS 1 and 2, and SPS 1 and 2. This request applies to all plant structures that contain concrete structural members exposed to the external atmospheric environment.

The both LRA, Section 3.5.1 and Appendix C, Sections C3.1.15, the applicant states that the concrete in question meets the code requirements to preclude the potential for freeze-thaw with the exception of the water-cement ratio at SPS. The applicant went on to explain that for SPS, the concrete mixtures (0.55) are slightly over the water-cement ratio code range (0.35 - 0.5). However, the applicant stated that their evaluation concludes that freeze thaw is not a concern since the concrete in question was tested and met the standards for air entrainment (in accordance with ASTM C-260), which can be considered in combination with water-cement ratio. Upon further evaluation, the applicant has determined that the water-cement ratio upper limit for freeze-thaw is 0,53 per ACI 318-63, Part III, Section 501(C) and ACI 318-71, Part 3 Section4.2.5. Additionally, the methods used to reconcile the water-cement ratio at Surry of 0.55 are in accordance with the guidance provided in NUREG-1557 regarding freeze-thaw.

The concrete at NAS meets code requirements for the water-cement ratio.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item 3.5-4 In both LRAs, Section 3.5.1, the information provided does not discuss operating experience regarding age-related degradation of containment concrete. Industry experience has shown that age-related concrete degradation has occurred at a number of plants, and some of the aging effects do warrant aging management.

Therefore, the staff requests that the applicant describe instances of aging degradation of accessible and inaccessible areas of containment concrete components at both NAS 1 and 2 and SPS 1 and 2 to justify the applicant's position of no applicable aging.

The applicant maintained that it is unaware of any ongoing aging that can adversely affect the intended function of the Containment for the period of extended operation. However, on the basis of the staff's concern, the applicant agreed to manage potential aging of the containment by crediting its existing ISI-IWL, Category L-A, inspection activities to manage any such aging.

The staff found the applicants response to this concern acceptable; however, the staff will provide an RAI to more formally document the information provided by the applicant.

Item 3.5-5 In both LRAs, Section 3.5.1 and Table 3.5.1-1, the information provided indicates that no aging effects of containment concrete and containment interior concrete components require aging management. However, for the containment concrete (dome, walls, and basemat) there has been sufficient operating experience that demonstrates the need for aging management of containment (e.g., NRC Secy-96-080, April 16, 1996, "...nearly one-half of the concrete containments have reported degradation related to the concrete or the post-tensioning system.") Consequently, 10 CFR 50.55a requires ISI of containment concrete in accordance with ASME Section XI, Subsection IWL (Examination Category L-A), and also specifies additional provisions beyond those required in Subsection IWL.

The applicant stated that the NAS and SPS containment designs do not use post-tensioning systems and, therefore, any associated aging management is not applicable to either facility. With respect to containment internal concrete components, the applicant repeated that there are no applicable aging effects for similar reasons as determined similar to the conclusions reached by Turkey Point and accepted by the staff in its SER for the Turkey Point LRA, Section 3.6.1.4.2.1.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item 3.5-6 The staff reviewed the aging effects for containment steel and elastomeric components, discussed in both LRAs, Section 3.5.1 and Appendix C, and concluded that a number of aging effects have not been addressed. These aging effects relate to containment hatches (loss of leak tightness due to mechanical wear), interface locations between the containment liner and concrete inside containment (loss of sealing due to deterioration of seals, gaskets, and moisture barriers (caulking, flashing, and other sealants)), inaccessible areas such as embedded containment steel liner (loss of material due to corrosion), aluminum portion of the reactor cavity seal at SPS 1and 2 (page 3-268 of the LRA), and structural steel sliding surfaces (wear of sliding surfaces (e.g., RPV support shoes)). Therefore, the staff requests that the applicant provide a technical justification for not including the aging effects described above in its AMR.

The applicant explained that it considered each of the areas identified by the staff in the following manner:

a. The applicant stated that it evaluated the potential for wear resulting from the movement of containment hatches (as an aging mechanism for loss of material that results in a loss of leak tightness due to mechanical wear), and determined that the frequency of hatch movement is not sufficient to affect the intended function. Regardless of the aging mechanism, the applicant notes that it does manage for the loss of material (the resulting aging effect of wear) associated with containment hatch components (door locking mechanisms, and personnel and equipment hatches) with its ISI activities, refer to Table -3.5.1-1. With regards to elastomers associated with containment hatches, the applicant uses its work control process performance testing activity (leak rate testing). This testing activity (in addition to the ISI inspection activity associated with the hatches) verifies, consistent with the applicable TS requirement(s) that a seal/established pressure boundary has been achieved prior to reliance on that intended function. The applicant also noted that it is required to meet all other associated TS requirements in accordance with its operating license.

b. The applicant stated that there is no sealant at the interface between the containment liner and concrete floor inside containment and, therefore, there is no applicable aging.

c. Inaccessible areas, such as embedded containment steel liner, were included in an AMR (refer to Table 3.5.1-1), and is managed by the containment ISI program (IWE), and the 10 CFR Part 50, Appendix B, corrective action program. In addition, the applicant recently excavated portions of the containment floor to inspect and verify that aging was not occurring in the inaccessible area of the interior liner plate. On the basis of more than 30 years of operating history and the inspection finding, the applicant believes that, if operating conditions remain the same, there is reasonable assurance that aging will not occur. If operating conditions change the applicant would be obligated to reassess the potential for aging to the inaccessible areas as part of its 10 CFR Part 50, Appendix B, corrective actions that applies to any failures that may occur in containment. In addition, if IWE inspections reveal findings associated with the accessible containment liner wall, the applicant again would be obligated to reassess the potential effects to the inaccessible areas as part of its 10 CFR Part 50, Appendix B, corrective actions that applies to these AMAs.

d. The applicant verified that it included the aluminum portion of the reactor cavity seal at SPS 1 and 2. The aluminum components in question are primarily exposed to an air environment, except during refueling when it is exposed to a borated treated water environment. The applicant determined that there are no aging effects associated with either material/environment combination.

e. The applicant confirmed that the structural steel sliding surfaces (e.g., RPV support shoes) are included in the nuclear steam supply system support and general structural support.

The structural steel sliding surfaces will be evaluated with the NSSS supports and general structural supports. The staff has no additional concerns relating to the applicant's response to these items.

Item 3.5-7 In both LRAs, Section 3.5.1 and Appendix C, the information provided states that some of the aging effects for containment steel components are not applicable to NAS 1 and 2 and SPS 1 and 2. However, there is no discussion to explain why other potentially applicable aging effects do not apply. In order for the staff to make a determination of whether all applicable aging effects are being managed, additional information is needed. Therefore, the staff requests that the applicant provide a technical justification for not identifying the aging effects listed below as applicable to containment steel components.

a. Loss of material due to corrosion for inaccessible areas (e.g., embedded containment steel liner), where examination of accessible areas may not be indicative of degradation in inaccessible areas.

Refer to the response to RAI 3.5-6 for interior inaccessible liner plate wall. For the exterior inaccessible liner plate wall, the applicant is considering periodic monitoring for aggressive groundwater that is being considered under RAI 3.5-2.

The staff will not need any additional information regarding this matter.

b. Cracking of steel due to stress-corrosion cracking, and flaw initiation and growth

The applicant explained that flaw initiation and growth are limited to Class 1 piping components and do not apply to any stainless steel structural components. For stress corrosion cracking, the stainless-steel structural components of concern in the containment are the fuel transfer tube, refueling cavity liner and electrical penetrations. With regard to the stainless steel transfer tube and refueling cavity liner, temperatures are maintained below 140 °F, as required by TS, eliminating the potential for stress-corrosion cracking. With regards to the stainless steel electrical penetration, these components are in an air environment, which also eliminates the potential for stress-corrosion cracking.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

c. Reduction in fracture toughness due to neutron embrittlement.

The applicant stated that the only component with sufficient neutron fluence for embrittlement to be a potential concern is the neutron shield tank, which is evaluated in the AMR for the NSSS supports.

The staff acknowledged the applicant's response, and will evaluate this concern in its review of NSSS supports.

Item 3.5-8 In both LRAs, Section B2.2.12, "Parameters Monitored or Inspected," the information provided indicates that portions of the containment liner may be painted or coated. However, it is not clear if a coatings program is relied upon to manage loss of material due to corrosion during the current licensing term (e.g., relief request from Subsection IWE). If so, then the coatings program needs to be continued during the period of extended operation. Therefore, the staff requests that the applicant explain whether a coating program is relied upon for managing loss of material due to corrosion during the current licensing term, if so, include the coatings program as an aging management program for the period of extended operation, and describe the coatings AMA(s).

The applicant verified that it does not credit a coatings program in the current licensing term for the application in question.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item 3.5-9 In both LRAs, Table 3.5.1-1 lists O-rings (with material group - EPDM, neoprene for NAS 1 and 2, rubber for SPS 1 and 2, and viton) as structural members. It is not clear as to what these items are and where they are used. Therefore, the staff requests that the applicant describe these structural components and to explain where they are used.

The applicant clarified that the O-rings of concern are the containment hatch seals, containment penetration seals, and the seals associated with the fuel transfer tube flanges. The AMR of these O-rings is addressed in Table 3.5.1-1 of the LRAs.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item 3.5-10 In both LRAs, Section B2.2.12, the information provided identifies the scope of the ISI Program - Containment, Subsection IWE, includes inspection activities from Categories E-A (containment surfaces), E-C (containment surfaces requiring augmented inspections), E-G (pressure-retaining bolting), and E-P (all pressure-retaining components). Categories E-B and E-F are identified as being optional in accordance with 10 CFR 50.55a(b)(2)(ix)(C). However, Category E-D (seals, gaskets, and moisture barriers) is not identified as being within the scope of the aging management program. Therefore, the staff requests that the applicant explain why this category is not included within the scope of the ISI Program - Containment Inspection.

The applicant explained that it more conservatively uses the work control program, which requires more thorough and more frequent inspections of these components to manage the aging of concern. Category E-D inspection activities are still performed consistent with the requirements of 10 CFR 50.55a.

The staff will request additional information relating to this concern, to more formally document the information provided during this telecommunication.

Item 3.5-11 In both LRAs, Appendix B, the information provided states that the ISI Program - Containment Inspection includes Category E-P (all pressure retaining components), which refers to 10 CFR Part 50, Appendix J, Option B. However, there is no description of the 10 CFR Part 50, Appendix J leak rate testing activity as an AMA. It is not clear as to whether the LRAs are crediting the entire 10 CFR Part 50, Appendix J, requirements as part of the ISI Program - Containment Inspection activity. Therefore, the staff requests that the applicant describe the 10 CFR Part 50, Appendix J program that is being credited for license renewal, or clearly state that the ISI Program - Containment Inspection activity is crediting the entire 10 CFR Part 50, Appendix J program.

The applicant stated that Option B is one means of fulfilling the requirements of 10 CFR Part 50, Appendix J. The applicant verified that it uses Option B, as approved by the staff, for both NAS and SPS.

The staff did not find the applicant's response complete. In previous discussions with the industry, the staff justified the need for an applicant to credit an integrated leak-rate program that is described in more detail in the LRA. Although the staff has determined that an integrated leak rate test performed in accordance with Appendix J, Option B, and consistent with the requirements in TS is one means of managing aging of the Containment structure, simple reference to the ISI Program - Containment Inspection including Category E-P, which in turn references Appendix J, Option B, is, in itself, not sufficient for the staff to make its determination. An applicant needs to more clearly document that the testing will be performed in accordance with Appendix J, Option B, and consistent with the associated requirements in applicable facility TS. The staff will provide an RAI that requests this level of detail in the description of this AMP.

Item 3.5-12 In both LRAs, Section 3.5.1 (under the heading "Environment"), the information provided indicates that the general air temperature in containment is not greater than 150 °F, and at hot pipe penetrations are exposed to elevated localized temperatures less than 200 °F. Elevated temperatures in the auxiliary building structures, other Class I structures (except the main steam valve house), and fuel buildings are not addressed in the LRAs, Sections 3.5.2 through 3.5.4. Therefore, the staff requests that the applicant describe any concrete locations in these structures that are subject to elevated temperatures. If elevated temperatures are experienced provide an AMR, including a description of the credited AMP.

The applicant verified that the air temperature for both plant containments are maintained below 150°F. In addition, the applicant stated that there are no known areas of localized air temperatures greater than 200°F. The applicant also noted that (with the exception of the main steam valve house) there are no known areas with elevated temperatures in the auxiliary building, other Class 1structures, or the fuel building.

The staff found the applicant's response to this concern acceptable; however, the staff will provide an RAI, to more formally document the information provided by the applicant.

Item 3.5-13 In both LRAs, Sections 3.5.2, 3.5.3, and 3.5.4, the information provided does not discuss plant-specific operating experience regarding age-related degradation of structural concrete members. Industry experience indicates that age-related degradation of concrete has occurred at a number of plants. ACI 349.3R was specifically developed to provide guidance for inspection of concrete nuclear structures other than the containment. Implementation of structures monitoring under the Maintenance Rule (10 CFR 50.65) includes inspection of concrete for age-related degradation. Therefore, the staff needs the applicant to recognize the potential aging of concrete and manage this aging as it relates to on-site structures that are within the scope of license renewal.

In follow-up discussions, the applicant maintained that it is unaware (with the exception of the SPS intake structure) of any ongoing aging that can adversely affect the intended function of any on-site structures for the period of extended operation. However, on the basis of the staff's concern, the applicant agreed to manage potential aging of the cntainment by crediting its existing ISI-IWL, Category L-A,as stated in RAI 3.5-4, above. The applicant will use the findings from these inspections as a leading indicator for potential aging of other on-site structures, and will take appropriate steps to address the aging of the containment structure and other on-site structures, as required by its 10 CFR Part 50, Appendix B, corrective action program.

The staff evaluated the applicant's response but remains concerned with the potential aging of these structures. There is sufficient industry operating experience that demonstrates the need for aging management of concrete nuclear structures. In addition, it is questionable whether an extrapolation for the period of extended operation can be made on the bases of the past performance or the on-going aging of the containment structure. ACI 349.3R was specifically developed to provide guidance for inspection of concrete nuclear structures other than containment. In addition, structures monitoring under the Maintenance Rule

(10 CFR 50.65) includes inspection of concrete for age-related degradation as part of each licensee's CLB. Based on the above discussion, the staff requests that the applicant either, implement an aging management program for the potential aging of the concrete nuclear structures (other than containment) that are within the scope of license renewal, or provide a technical justification for not managing the associated aging, such that there is reasonable assurance that the intended function(s) will be maintained consistent with the CLB throughout the period of extended operation.

The staff will provide an RAI requesting the needed information.

Item 3.5-14 In both LRAs, Section 3.5.2 and Table 3.5.2-1, the information provided indicates that cracking of masonry block walls is the only aging effect requiring management for concrete structural members of the auxiliary building structure. However, there has been sufficient industry operating experience that demonstrate the need for aging management of concrete nuclear structures. On the basis of the above discussion, provide a technical justification for excluding aging management of concrete for the purpose of license renewal. (This RAI also applies to the concrete structural members of other Class I structures (LRA, Section 3.5.3) and fuel building (LRA, Section 3.5.4).

The applicant noted that this question, as it relates to concrete structures, is encompassed by RAI 3.5-13, and its response under question 3.5-13 will adequately address this concern. With respect to internal concrete components, the applicant repeated that there are no applicable aging effects for similar reasons as determined by Turkey Point and accepted by the staff in its SER for the Turkey Point LRA, Section 3.6.2.3.2.1 and 3.6.2.3.2.2.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item 3.5-15 In the NAS LRA, Section 3.5.3 and Table 3.5.3-8, the applicant states that the concrete walls and foundation mat slab in the service water pump house are exposed to a raw water (service water reservoir) environment. However, no aging effects requiring management are identified. Therefore, the staff requests that the applicant identify where in the LRA are the aging effects for the service water pump house concrete walls and the foundation mat slab discussed, or provide a technical justification for the determination that there are no applicable aging effects.

The applicant stated that the service water pump house concrete walls and the foundation mat slab are within the scope of license renewal and subject to an AMR. However, chemical analysis and operating experience show that the reservoir water is non-aggressive and there is no associated aging of the structures of concern.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item 3.5-16 In both LRAs, Section 3.5.4 and Table 3.5.4-1, the information provided identifies the loss of material from carbon steel and low-alloy steel in air, atmosphere/weather, or borated water leakage environments, and the loss of material from stainless steel structural members in the treated water (borated water) environment of the spent fuel pool, as applicable aging effects requiring aging management. However, cracking of stainless steel due to SCC in a borated water environment of the spent fuel pool was not identified as an applicable aging effect. Therefore, the staff requests that the applicant identify where in the LRA is cracking of the spent fuel pool liner plate discussed, or provide a technical justification for excluding cracking as an applicable aging effect requiring management.

The applicant noted that this concern is discussed under question 3.5-7b, and its response to question 3.5-7b satisfies this concern.

The staff will not need any additional information regarding this matter.

Item 3.5-17 The staff notes that monitoring leakage from the spent fuel pool is an essential element of aging management for the spent fuel pool stainless steel liner. The chemistry control program for primary systems is a preventive program aimed at precluding conditions conducive to degradation. Its effectiveness is evaluated by some direct measurement that indicates the absence of degradation. Monitoring the water level in the spent fuel pool is the minimum acceptable method for verifying integrity of the pool liner. Therefore, the staff requests that the applicant describe the current plant specific procedures for monitoring leakage from the spent fuel pool, or provide a technical justification for not crediting these procedures as an adjunct to the chemistry control program for primary systems.

The applicant explained that spent fuel pool level is continuously monitored by a control room alarm to maintain sufficient spent fuel pool cooling, and not by any specific procedure. If level drops below the alarm set-point, then control room operators are required to take proceduralized corrective actions.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Section B2.1.2, "Infrequently Accessed Area Inspection Activities"

Item B2.1.2-1 In both LRAs, Section B.2.1.2, the applicant identifies the systems, structures and commodities that credit the infrequently accessed area inspection activities for managing the aging effect of loss of material. This section also states that the scope of these activities includes "representative regions and equipment in the following areas." The specific areas for NAS 1 and 2 and SPS 1 and 2 are then listed. In order to fully understand the scope of this activity and its technical bases, the staff requests that the applicant provide the following information:

a. What criteria were used for selecting the infrequently inspected areas listed for each unit? The applications refer to "representative regions and equipment," implying a sample of the areas and equipment that are managed by the infrequently accessed area inspection activities. Is the list of specific areas managed by the infrequently accessed area inspection activities a complete list of infrequently accessed areas. To what extent did the selection process consider locations identified in NRC Information Notice 97-46, "Unisolable Crack in High-Pressure Injection Piping," or other reported operating experiences?

   The applicant stated that the list provided in Section B2.1.2 is a complete list of infrequently accessed areas. The applicant also explained that any area of the plant that contains any SSCs within the scope of license renewal and subject to an AMR, that is not routinely accessible because of radiation levels, temperature, operationally flooded areas, or physical obstructions (behind or beneath concrete walls) was considered an infrequently inspected area. Finally, with reference to NRC Information Notice 97-46, the applicant stated that this generic communication is not applicable to the infrequently accessed area inspection activities. This AMP consists of a one-time inspection to assess the aging of structures and components located in areas not routinely accessible. The information notice in question, although not specifically applicable to NAS and SPS, is concerned with the cracking of a 2-inch make-up line in the MU/HPI system, which is more specifically applicable to the AMR of the ESF, Section 3.2.5.

   The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

b. Clarify that some portion of all systems, structures, and commodities, as well as the different materials and environments, that credit this activity, are included in the infrequently accessed areas inspection activities. If not, explain the technical basis for any omissions.

   The applicant confirmed that some portion of all systems, structures, and commodities, as well as the different materials and environments, that credit this activity, are included in the infrequently accessed areas inspection activities.

   The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

c. Clarify what is meant by "representative regions and equipment." Does this phrase include the following items housed within each specific area that has been identified:

(i) steel and concrete walls, beams, and columns
(ii) piping and fittings
(iii) pumps and valves
(iv) other equipment and/or components (e.g., filters, tanks, condensate coolers/condensers, ion exchangers, strainers, heat exchangers)

The applicant explained that it did not mean to limit the scope of SSCs by the use of "representative regions and equipment," and all of the structures, supports, piping, and equipment within each specific area/region is included within the scope of the inspection.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item B2.1.2-2 Clarify that the list of degradation or adverse conditions provided under the heading "Parameters Monitored or Inspected," on page B-13 of the NAS LRA are those that will be investigated under the infrequently accessed areas inspection activities. Specifically, explain why cracking (of concrete, supports, equipment, sealants) is included on the list of degradation or adverse conditions since the scope of this activity is limited to managing the aging effect of loss of material. In addition, if cracking is to be investigated under this activity, explain why cracking of steel structures or piping is omitted.

The applicant clarified that the list of aging effects provided under "Parameters Monitored and Inspected" is a complete list of aging effects that will be managed by the infrequently accessed areas inspection activities. The applicant also explained that the cracking of concrete referenced under this AMP refers to the concrete associated with the applicable piping and equipment anchors that can potentially affect the intended function of the associated anchor. The aging management of pipe cracking is addressed under the AMR for the specific systems, as appropriate.

The staff found this response acceptable and will not need any additional information regarding this matter.

Item B2.1.2-3 Explain the qualifications of the personnel performing the inspections, as well as those that may evaluate any indications. Furthermore, describe the standards (such as the ASME Code and 10 CFR Part 50, Appendix B) that are used to develop the inspection procedures.

The applicant explained that the qualifications of the personnel performing the inspections and evaluating the associated indications will be consistent with the applicable ASME code qualifications for inspectors.

The staff found this response acceptable and will not need any additional information regarding this matter.

Section B2.2.1, "Augmented Inspection Activities"

Item B2.2.1-1 The "Scope" section of the augmented inspection activities described in Appendix B2.2.1 of the LRAs includes a table for NAS 1 and 2 and SPS 1 and 2 that summarizes the test methods and frequency of the examinations for inspection items that are within the scope of license renewal. Confirm that the information listed in this table, as well as the corresponding acceptance criteria for each item, are being performed consistent with the augmented inspection activities as required under its CLB. Provide a discussion of the technical basis for any differences.

The applicant verified that the information listed in this table, as well as the corresponding acceptance criteria for each item, are consistent with the augmented inspection activities currently being performed under its CLB.

The staff found this response acceptable and will not need any additional information regarding this matter.

Item B2.2.1-2 With regard to the discussion on "Operating Experience," please provide specific information regarding the operating experience with the existing program at NAS 1 and 2 and SPS 1 and 2. This should include a discussion of past corrective actions resulting in program enhancements or additional programs. This information should demonstrate where the existing program has succeeded and where it has failed (if at all) in intercepting aging degradation in a timely manner.

The applicant agreed to provide a more detailed description of the applicable operating experience.

The staff will provide an RAI requesting that the applicant provide additional information regarding operating experience associated with the augmented inspection activities.

Item B2.2.1-3 In the "Scope" section of the Augmented Inspection Activities described in Appendix B2.2.1 of the LRA, the applicant states that: "As a Licensee Follow-up Action, the station will implement an augmented examination of the pressurizer surge line connection to the reactor coolant system's hot-leg loop piping prior to the end of the current operating license. These examinations will address the issue of thermal fatigue failure of welds due to environmental effects, GSI-190 (Reference19). Additionally, a licensee follow-up action will be implemented to include inspection of the core barrel hold-down spring as one of the augmented inspection activities. The initial inspection of the core barrel hold-down spring will be performed prior to the end of the current operating license." Explain why this commitment is not included in Section A2.2.1 of the FSAR Supplement.

In response to RAI B2.2.9-5, the applicant committed to including the follow-up action items listed in the LRA, Table B4.0-1, in the FSAR Supplement. The staff will provide an RAI requesting that the applicant include these items in the FSAR Supplement as a result of its original request for addition information (RAI B2.2.9-5).

No additional action is required in response to this item.

Sections B2.2.4, "Chemistry Control Program for the Primary Systems"

Item B2.2.4-1 The applicant includes structures and a commodity (general structural supports) that credit the chemistry control program for primary systems for managing the aging effects of loss of material and cracking. Since this program monitors fluid for specific parameters within a system or component, clarify how this AMP will mitigate aging effects in structures and supports.

The applicant walked the reviewers through the AMR tables in Section 3 of the LRAs and demonstrated to the reviewer that the structural components associated with this aging management program are all, at times, in a treated water environment.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item B2.2.4-2 With regard to the discussion on "Parameters Monitored or Inspected:"

a. In both LRAs, Section B2.2.4, "Monitored Primary Chemistry Parameters," the applicant identifies the chemistry parameters that are monitored in accordance with EPRI guidelines. Clarify if there are any exceptions to the EPRI guidelines for each item in the tables. If so, provide a discussion of the technical bases for any differences.

   The applicant verified that the chemistry parameters monitored by this chemistry monitoring program are at a minimum complete, and consistently more conservative than the parameters in the EPRI guidelines. The applicant does monitor some additional parameters that are not identified in the EPRI guidelines.

   The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

b. Crud (i.e., the corrosion product) has been identified as one of the chemistry parameters that is monitored for the primary system. Describe the technique for measuring crud in the primary system. Include a description of the procedure for selecting the most likely region for deposition in various components within the primary system and how crud affects the intended functions of these components.

The applicant explained that crud is the same as suspended solids and that they do monitor for this impurity for intrusion into, and potential clogging of, the control rod drive mechanisms and the seal injection lines for the reactor coolant pumps.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

c. Clarify that the program includes provisions to maintain and verify the integrity of the samples to ensure that the method of sampling and storage will not cause a change in the concentration of the chemical species in the samples. Is the program proceduralized, controlled under your Appendix B program, and does it specifically address the handling of specimens.

The applicant explained that it has sample and analysis procedures to control the quality of the sampling and analysis techniques. They verified that these procedures are controlled by its 10 CFR Part 50, Appendix B program.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Sections B2.2.5, "Chemistry Control Program for Secondary Systems"

Item B2.2.5-1 Provide the following information regarding the "Parameters Monitored or Inspected":

a. In both LRAs, Section B2.2.5, "Monitored Secondary Chemistry Parameters," the applicant identifies the chemistry parameters that are monitored in accordance with EPRI guidelines. Clarify if there are any exceptions to the EPRI guidelines for each item in the tables. If so, provide a discussion of the technical bases for any differences.

The applicant verified that the chemistry parameters monitored by this chemistry monitoring program are at a minimum complete, and consistent with, or more conservative than the parameters in the EPRI guidelines. The applicant does monitor some additional parameters that are not identified in the EPRI guidelines.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

b. Clarify that the program includes provisions to maintain and verify the integrity of the samples to ensure that the method of sampling and storage will not cause a change in the concentration of the chemical species in the samples. Is the program proceduralized, and controlled under the Appendix B program, and does it specifically address the handling of specimens.

The applicant explained that it has a sample and analysis procedures to control the quality of their sampling and analysis techniques. The applicant verified that these procedures are controlled by its 10 CFR Part 50, Appendix B program.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Sections B2.2.7, "Fire Protection Program"

B.2.2.7-1 The Scope section of the fire protection program identifies some of the applicable component groups listed in Tables 3.3.9-1 and 3.5.11-1 of the LRA, but not all. For example, there is no mention of tanks, expansion joints, seismic gap covers, as well as others. Clarify that the scope of this AMP includes all of the component groups identified in the above tables. If there are any exceptions, please provide a technical explanation.

The applicant verified that it provides an adequate scope of the program in the scoping summary through the commodities listed in Appendix B and the hyperlinks to the appropriate tables in Sections 2 and 3 of the LRAs.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

B.2.2.7-2 There is no mention under preventive actions of the need to perform periodic flushing of the water-based fire protection systems. If periodic flushing is not performed, explain the preventive actions used to ensure that no significant corrosion, MIC, or biofouling has occurred.

The applicant verified that periodic flushing is not performed for the application in questions. However, the applicant does perform an annual full-flow test to ensure that no significant corrosion, MIC, or biofouling has occurred and that adequate pressure and flow rates are available to meet the intended function.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

B.2.2.7-3 Provide the following information regarding the "Parameters Monitored and Inspected":

a. In both LRAs, the applicant states that penetration seals are checked for an adequate amount of fire-stop material. Clarify whether these inspections include examinations for any sign of degradation such as cracking, seal separation from walls and components, separation of layers of material, rupture, and puncture of seals that are directly caused by increased hardness and shrinkage of seal material due to weathering. If not, explain the technical basis for the inspections that are performed.

The applicant agreed that it should have included a more detailed description of the parameters monitored during its inspection activities.

The staff will provide an RAI requesting that the applicant provide a complete description of the parameters monitored for the penetration seals.

b. Clarify whether the monitoring of the performance of the water systems for fire protection include sequential starting capability tests and controller function tests for detecting any degradation of the fuel supply line for the diesel-driven fire pump. If not, explain how the fuel line is monitored to ensure that it can perform the intended function.

The applicant verified that it performs surveillance to verify that the fuel supply line is functional.

The staff will provide an RAI requesting that the applicant describe its AMA to verify that the fuel supply line is functional.

c. Clarify whether the monitoring of the halon/carbon dioxide fire suppression systems includes functional tests to determine the suppression agent charge pressure and that the extinguishing agent supply valves are open and the system is in automatic mode. If not, explain how these systems are monitored to ensure its intended function.

The staff and applicant discussed this concern and determined that the question was not age-related and, therefore, was beyond the scope of license renewal

The staff will not need any additional information regarding this matter.

Item B2.2.7-4 Provide the following information regarding the detection of aging effects;

a. Initially the staff requested that the applicant clarify whether portions of the above-ground fire protection piping and fire suppression piping are disassembled and visually inspected internally during each refueling outage to identify evidence of loss of material due to corrosion. Upon further evaluation, the staff reaffirmed that uniform general corrosion of internal fire suppression piping is an applicable aging effect requiring aging management. However, internal inspection was determined not to be the preferred means of aging management because of the potential to re-oxygenate the system and accelerate the applicable aging effect each time the system is opened. Therefore, the staff recommends that the applicant perform a one-time non-intrusive inspection of a representative sample of fire suppression piping, near the end of the current operating term, and a second inspection within a reasonable length of time (within one refueling cycle) after the 50-year sprinkler head testing/inspection activity required by the National Fire Protection Association (NFPA). During these inspections, the applicant needs to verify that excessive wall thinning has not occurred, such that it may adversely affect the pressure boundary intended function of the system. In addition, the applicant needs to verify that the inner diameter of the pipe will provide sufficient system pressure to meet its intended function. As an alternative, the applicant can consider using its work control process as long as they can demonstrate that sufficient inspections of a representative sample of system piping is performed at an adequate frequency. The only other plausible alternative acceptable to the staff at this time is for an applicant to provide a technical justification, consistent with the material(s) and environment(s), that aging will not occur within the portions of this system that are within the scope of license renewal and subject to an AMR.

The applicant stated that it currently does not inspect above ground fire protection piping and fire suppression piping internally for the purpose of license renewal. The applicant needs to evaluate it current programs and activities, and aging management requirements before responding to this question.

The staff will provide an RAI requesting that the applicant describe its AMA to manage the loss of material on inside surfaces of piping so that the system's function is maintained.

c. In the LRAs, the applicant states that during the period of extended operation, a representative sample of sprinklers that have been in service for 50 years will be replaced or tested in accordance with the requirements of NFPA-25, Section 2-3.1.1. Clarify that the NFPA guidance to perform this sampling every 10 years after the initial field service testing will also be followed.

The applicant stated that it did not discuss replacing or testing every 10 years beyond the initial 50-year replacement or test because that would bring them to the end of the period of extended operation. However, the applicant stated that it is committed to NFPA-25, Section 2-3.1.1, and if they were to operate 10 years beyond the 50-year replacement or test of the sprinkler heads, it would be required to perform the follow-up 10-year replacement or test.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

B.2.2.7-5 The discussion on monitoring and trending in the LRAs states that various types of fire protection equipment are visually inspected at frequencies that vary from 31 days to 3 years. More specific information is needed. Provide the inspection/test frequencies and discuss the technical bases for the following items:

a. penetration seals (including percent of each type inspected each time)
b. fire doors inspected for holes in the skin, clearances, wear or missing parts
c. functional tests of fire doors to verify the operability of automatic hold-open, release, closing mechanisms and latches
d. visual and functional tests of the halon/carbon dioxide fire suppression systems
e. inspections to verify that the extinguishing agent supply valves are open and the system is in automatic mode
f. visual inspection of yard fire hydrants
g. fire hydrant hose hydrostatic tests, gasket inspections, and fire hydrant flow tests
h. sprinkler systems

The applicant agreed to provide the specific frequencies for the applicable inspection activities requested above.

The staff will provide an RAI requesting that the applicant provide the above mentioned inspection activities, with the exception of items "d," and "e" because the applicant's AMR determined that there are no applicable aging effects for those two items.

Item B2.2.2.7-6 In both LRAs, Section B2.2.2.7, the applicant's discussion on operating experience does not reference NRC Generic Letter 92-08 and NRC Information Notices 88-56, 91-47, 94–28, 97-70. Discuss the extent to which the fire barrier experiences reported in these references have been incorporated in the Fire Protection Program.

The applicant agreed to provide a more detailed description of the applicable operating experience.

The staff will provide an RAI requesting that the applicant provide additional information regarding the applicable operating experience.

Section B2.2.9, "General Condition Monitoring Activities"

Item B2.2.9-1 The NAS LRAs, Section B2.2.9, the applicant states that the scope of the General Condition Monitoring Activities includes managing the aging effect of separation and cracking/delamination for NAS 1 and 2. The SPS LRA does not state that the General Condition Monitoring Activities includes managing the aging effect of separation and cracking/delamination for SPS 1 and 2. The following additional information is needed with regard to the scope of this AMP:

a. Confirm that SPS 1 and 2 do not use fire wraps. If this is not the case, explain which AMP manages the applicable aging effects for fire wraps at SPS 1 and 2.

The applicant confirmed that SPS does not use fire wraps.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

b. In the NAS LRA, Table 3.5.11-1, the applicant states that the General Condition Monitoring Activities are used to manage the aging effects for fire wraps. The NAS LRA, Sections A2.2.7 and B2.2.7, state that the Fire Protection Program is used to manage aging of fire wraps. Please discuss any discrepancies in information provided in the LRA and clarify what aging management programs and/or activities are used to manage aging of fire wraps.

The applicant stated that the statements in the NAS LRA, Section A2.2.7 and B2.2.7 are administrative errors and that the fire protection program is not used to manage aging of fire wrap.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item B2.2.9-2 Both LRAs, Section B2.2.9, under "Parameters Monitored or Inspected," contain a list of the types of degradation or adverse conditions that can be detected by visual inspections. The following information is needed with regard to this section:

a. Both LRAs contain the following statement: "[t]he following types of degradation or adverse conditions can be detected by visual inspections." Please verify that the intent of this statement is to indicate that the listed degradations and adverse conditions **<u>will be detected, as applicable,</u>** by the general condition monitoring activities.

The applicant confirmed that the intent of the statement in question was to indicate that the listed degradations and adverse conditions **<u>will be detected, as applicable,</u>** by the general condition monitoring activities.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

b. Clarify why cracking of concrete appears on the list, since concrete structures do not appear to be within the scope of this AMP.

The applicant stated that the cracking of concrete referenced in this AMP is the concrete associated with anchors, which can affect the intended function of these anchors.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

c. Clarify whether cracking in concrete in the vicinity of piping and equipment anchorage supports, as well as other structural supports, is included in the scope of this AMP. If not, explain which AMP manages such aging effects.

The applicant confirmed that the cracking of concrete referenced under this AMP is the concrete associated with piping and equipment anchors, which can affect the intended function of these anchors.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

d. Clarify whether cracking in piping is included in the scope of this AMP. If not, explain which AMP manages such aging effects for the systems included in the scope of this AMP.

The applicant clarified that the cracking in piping is not included in the scope of this AMP. The applicant further stated that different AMPs, as identified throughout Section 3 of the LRAs, are managed by different programs depending on materials, environments, and locations.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item B2.2.9-3 In both LRAs, Section B2.2.9, under "Monitoring and Trending," reference is made to the use of a "spaces approach" for visual monitoring. Explain what is meant by "spaces approach." Also, clarify that all supports, piping, doors, and equipment in all of the systems, structures and commodities that are included in the scope of this program are inspected at least once per refueling outage. If not, explain the inspection frequency for full coverage of all the items in the scope of this AMP and the technical basis for the approach.

The applicant described its "spaces approach" with respect to general condition monitoring visual inspection as a general inspection of the structures and components by room or area of the plant versus by system

The staff found the applicant's description acceptable, but requested that the applicant provide this information in writing. Therefore, the staff will provide an RAI requesting a description of the applicant's spaces approach.

Item B2.2.9-4 In both LRAs, Section B2.2.9, under "Operating Experience," additional information is needed. Provide specific information regarding the operating experience regarding this existing program at NAS 1 and 2 and SPS 1 and 2. This operating experience information should include a discussion of past aging and/or failures detected, and any corrective actions resulting in program enhancements or additional programs. A past failure would not necessarily invalidate an AMP because the feedback from operating experience should have resulted in appropriate program enhancements or new programs. This information should demonstrate where the existing programs have succeeded and where these programs have failed (if at all) in intercepting aging degradation in a timely manner.

The applicant agreed to provide a more detailed description of the applicable operating experience.

The staff will provide an RAI requesting that the applicant provide additional information regarding the applicable operating experience.

Item B2.2.9-5 Both LRAs, Section B2.2.9, identify the following two licensee follow-up actions: (1) Additional procedural guidance will be developed to direct thorough and consistent inspections of component supports and doors. Initial inspections will be completed, using the additional guidance, prior to the end of the current operating license, and (2) Procedural guidance will be developed for engineers and health physics technicians regarding inspection criteria that focus on detection of aging effects during General Condition Monitoring Activities. The guidance will be developed prior to the end of the current operating license. These commitments need to be included in Section A2.2.9 of the FSAR Supplement.

The applicant agreed to include this information in the FSAR Supplement. The applicant stated that it may include the follow-up actions for each activity separately in the appropriate subsection of the FSAR Supplement, or simply include all the follow-up actions as a single listing.

The staff will provide an RAI requesting that the applicant include the follow-up actions in its FSAR Supplement.

Section B2.2.17, "Service Water System Inspections"

Item B2.2.17-2In both LRAs, Section B2.2.17, under "Preventive Actions," the applicant states that no preventive actions are performed. The recommendations of GL 89-13 include control or preventive measures and it appears that some measures are included in this AMP. The following information is needed:

a. Both LRAs, in the introduction to Section B2.2.17 state that biocide is added to the service water system to reduce biological growth (including MIC). The staff considers this to be a preventive action; thus the section on "Preventive Actions" should be revised to reflect this commitment or an explanation provided as to why this is not considered to be a preventive action.

The applicant agreed that they should have considered injection of a biocide to be a preventive action.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

b. Clarify if the program includes flushing of infrequently used systems as recommended by GL 89-13. If not, explain why this recommendation has not been followed.

The applicant explained that the only infrequently used system that fall within the scope of GL 89-13 is the containment recirculating spray heat exchange service water supply line, and that line is maintained in dry-layup and, therefore, do not need to be flushed.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item B2.2.17-3The following additional information is need regarding both LRAs, Section B2.2.17, under "Parameters Monitored or Inspected":

a. The applicant does not provide any indication that the piping, components, heat exchangers and the internal linings or coatings are inspected for cleanliness to ensure removal of accumulations of biofouling agents, corrosion products, and silt. If not, explain why inspections for cleanliness for all of these items are not included in the program.

The applicant explained that, for the purpose of license renewal, it is concerned with maintaining the intended function of the components of concern. Maintaining a cleanliness standard is beyond the scope of license renewal. However, the applicant restated that their program is consistent with the requirements/guidance in GL 89-13, and will provide the necessary cleanliness to provide reasonable assurance that the intended function is maintained.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

b. In both LRAs, the applicant states that inspection of components exposed to service water are performed to check for changes in material properties for components made of copper and copper alloys. Explain what change in material properties the program is attempting to detect and how this will be accomplished by visual inspections.

The applicant stated that they inspect for changes in color and texture for selective leaching and de-alloying.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item B2.2.17-4In both LRAs, Section B2.2.17, under "Detection of Aging Effects" the applicant states that volumetric inspections are performed to check for loss of material due to MIC for NAS 1 and 2. Explain why such volumetric inspections are not performed for SPS 1 and 2, as well.

The applicant explained that operating experience has shown that NAS lake water creates an environment where MIC is a concern in its service water system, making volumetric exams necessary to provide reasonable assurance that the associated aging will be properly managed for the period of extended operation. However, SPS operating experience shows that MIC is not a concern for the river water used at SPS and, therefore, volumetric exams are not necessary to provide reasonable assurance that MIC will be properly managed for the period of extended operation at SPS 1 and 2.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item B2.2.17-5Both LRAs, Section B2.2.17, under "Monitoring and Trending," clarify that the inspection and testing frequencies for the extended period of operation will continue to be in accordance with the applicant's commitments under NRC GL 89-13. If not, explain the technical basis for any differences.

Both applications contain a statement that the service water system inspection program is consistent with the requirements/guidance in NRC GL 89-13. This statement includes inspection frequencies.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item B2.2.17-6Both LRAs, Section B2.2.17, the applicant states that the acceptance criterion for visual inspections is the absence of anomalous indications that are signs of degradation. Clarify whether the program also includes acceptance criteria based on effective cleaning of biological fouling organisms and maintenance of protective coatings or linings. If not, explain why such criteria are not part of the program.

The applicant agreed to provide a more detailed description of the acceptance criteria for visual inspections.

The staff will provide an RAI requesting that the applicant provide additional information regarding the acceptance criteria for visual inspections.

Section B2.2.19, "Work Control Process"

Item B2.2.19-1Both LRAs, Section B2.2.19, clarify whether the following items are editorial. If not, provide a technical discussion for any changes.

a. On page B-119 of the LRA for NAS, the third bullet near the bottom of the page ends with "; and." This implies that another item should follow. The sentence should be corrected, or the missing item should be added.

   The applicant stated that the "and" was an editorial error and it should be removed.

   The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

b. This item may relate to (a) above. Section A2.2.19 on Page A-25 of the NAS LRA includes two boxed items related to "water treeing." Similar information is not included in Section B2.2.19 of the LRA. Either correct Page A-25 or include the appropriate information in Section B2.2.19 of the LRA.

   The applicant stated that including the two boxed items relating to "water treeing" was an administrative error, and should not have been included on Page A-25. Therefore, the staff should not consider this information during its evaluation.

   The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

Item B2.2.19-2In both LRAs, Section B2.2.19, under "Scope," the applicant identifies the systems, structures and commodities that credit the work control process. In some cases, the tables in Section 3 of the LRA that summarize the AMR results referenced more than one AMP for the same item. Please clarify in general terms how the work control process is coordinated with other AMPs, with particular emphasis on how the scopes of the multiple AMPs are reconciled and which AMP controls in the event that there are differences in commitments related to inspection/testing frequencies and acceptance criteria. To aid in the response to this request, provide a detailed discussion of the above for the following three examples from the NAS AMR tables:

Page 3-163, Table 3.3.3.-2 which refers to both the work control process and service water system inspections for managing the aging effects of heat transfer degradation and loss of material in a raw water environment for stainless steel tubes in the Unit 1 component cooling heat exchangers.

Page 3-246, Table 3.4-4 which refers to the Work Control Process, Chemistry Control Program for Secondary Systems, Secondary Piping and Component Inspection and Tank Inspection Activities for managing the aging effect of loss of material in a treated water environment for carbon and low-alloy steel pipe in the feedwater system.

Page 3-318, Table 3.5.11-1 which refers to the work control process, fire protection control program and general condition monitoring activities for managing the aging effect of loss of material in an air environment for carbon and low-alloy steel fire doors and/or EQ barrier doors.

The applicant provided a discussion on the three examples requested by the staff and, as a result, satisfied the staff's concern. They clarified the fact that when more than one AMP is referenced, the programs are intended to be supplementary such that the requirements of all listed programs are satisfied.

The staff found the applicant's discussion acceptable, and will not need any additional information regarding this matter.

Item B2.2.19-3In both LRAs, Section B2.2.19, under "Monitoring and Trending," the applicant states that "[a] review of maintenance data for the past seven years at SPS indicated that the inspection opportunities available through the Work Control Process exceeded the minimum number of random samples necessary to obtain a 90/90 confidence level that aging effects would, if present, be identified. Therefore, sufficient inspection opportunities are available to provide reasonable assurance that systems are adequately monitored." It is also stated on Page B-115 of the NAS LRA that EPRI Report TR-107514 shows that a population sample size of 25 provides a 90/90 confidence level for an infinite sample population. A table is presented on Page B-116 of the NAS LRA to support the statement: "[a]s indicated in the table, the extent of material/environment combinations, and the ample number of work control opportunities that exist, eliminates the need to schedule specific inspections."

On the based of these statements, it is the staff's understanding that no specific inspection schedules are established for the items covered under the scope of this AMP, but there will be an adequate number of work opportunities for each material/environment combination during a time period of approximately two refueling cycles (Reference Page B-117 of the NAS LRA). The following information is needed to fully understand the approach and the supporting technical bases:

a. Confirm that the staff's understanding is correct. If not, provide a more detailed discussion on this matter.

The applicant confirmed that the staff's understanding is correct.

The staff found the applicant's response acceptable and will not need any additional information regarding this matter.

b. Provide a complete list of all materials and environments that are within the scope of this AMP and the corresponding sample opportunities similar to the information in the table on Page B-116 of the NAS LRA. If the data on sample opportunities is not available, explain how the information in the table is extrapolated to include all material and environment combinations.

The applicant explained that the information contained in the table is provided by commodities and the environments that are most susceptible to aging, not by individual components. In response to the staff's request for specific information relating to expansion joints, O'rings, and ductwork, the applicant provided the following information:

Expansion joints and O-rings are included as part of the commodity for the service water system, non-matallic materials, exposed to air

With respect to ductwork, the applicant explained that, although ductwork is included within the scope of license renewal and subject to an AMR, there is no applicable aging effect for galvanized steel in a controlled air environment and, therefore, it did not need to be included in this table.

After discussions with the applicant, the staff still had concerns with the approach from EPRI Report TR-107514, and discussed these concerns with the applicant. The applicant understood the staff's concern and clearly stated that did not intend for the staff to perform an evaluation on EPRI Report TR-107514, and withdraws its reference and the associated information presented in B2.2.19. The applicant will provide the necessary information requested in an RAI.

The staff will develop an RAI requesting information that will provide reasonable assurance that the work control process will adequately manage the applicable aging effects without an established frequency for the inspections provided by the program. The staff will ask the applicant to demonstrate that there is sufficient operating history to show that the applicant enters each system that credits the work control process frequently enough such that there is reasonable assurance that periodic inspections will be performed during the period of extended operation.

c. Explain what provisions are in place to verify that there have been at least 25 work opportunities during each period of two refueling cycles for each material/environment combination identified in response to item (b). If the number of work opportunities is found to be less that 25 for the given period, what provisions are in place to correct the deficiency?

The work opportunities identified in the table is a conservative representation of "the EPRI sample size criterion," because the EPRI sample size criterion is not time limited. The criterion is the sample size (25 samples) needed for a 90/90 confidence level for an infinite population of opportunities. The applicant stated that using a 7-year evaluation period is a more conservative evaluation because it limits the population to some value less than an infinite number of opportunities.

Because the applicant withdrew its reference to the EPRI report, this item is no longer applicable.

d. On Page B-121 of the NAS LRA the applicant states that "[a]s a Licensee Follow-up Action, changes will be implemented into the maintenance procedures to provide reasonable assurance that consistent internal inspections will be completed during the process of performing maintenance tasks. These changes will be implemented prior to the end of the current operating license." In order to understand this commitment, explain the type and corresponding purpose of the changes that will be implemented. Also, explain what provisions will be provided to ensure that the inspections and tests performed as part of the maintenance tasks are performed by qualified personnel who have full knowledge of the type and scope of the inspections and tests to be performed.

The applicant agreed to provide a more detailed description of the proposed type(s) of, and corresponding purpose(s) for, the changes to the maintenance activities discussed under the work control process. The applicant also agreed to provide a discussion about the qualification of individuals performing the applicable maintenance activities.

The staff will provide an RAI requesting that the applicant provide additional information regarding the acceptance criteria for visual inspections.

e. The commitment referred to in item (d) needs to be included in Section A2.2.9 of the FSAR supplement.

In response to RAI B2.2.9-5, the applicant committed to include the follow-up action items listed in the LRA, Table B4.0-1, in the FSAR Supplement. The staff will provide an RAI requesting that the applicant include these items in the FSAR Supplement as a result of its original request for addition information (Item B2.2.9-5).

No additional action is required in response to this item.

Item B2.2.19-4 Both LRAs, Section B2.2.19, under, "Operating Experience," provide specific information regarding the operating experience with the existing Work Control Process at NAS 1 and 2 and SPS 1 and 2. This should include a discussion of past corrective actions resulting in program enhancements or additional programs. A past failure would not necessarily invalidate an AMP because the feedback from operating experience should have resulted in appropriate program enhancements or new programs. This information should demonstrate where the existing program has succeeded and where it has failed (if at all) in intercepting aging degradation in a timely manner.

The applicant agreed to provide a more detailed description of the applicable operating experience.

The staff will provide an RAI requesting that the applicant provide additional information regarding the applicable operating experience.

The staff provided a draft of this telephone conversation summary to VEPCO to allow them the opportunity to comment on the contents of its input prior to the summary being issued.

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Telecom Participants by Topic

Section 2, "Scoping"

Michael Henig	VEPCO
Chang Li	NRC
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Section 2.3.3.7, "Service Water "

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Meena Khanna	NRC
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Sections 3.1.1, "Reactor Coolant System Piping And Associated Components"

Dave Wootten	VEPCO
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Sections 3.1.2, "Reactor Vessel"

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Attachment

Section 3.1.3, "Reactor Vessel Internals"

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Section 3.1.4, "Pressurizer"

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Section 3.2, "Aging Management of Engineered Safety Feature Systems"

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Sections 3.3.9, "Fire Protection and Supporting Systems"

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Section 3.5, "Aging Management of Structures and Component Supports"

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Yong Kim	NRC
Kamal Manoly	NRC
Robert Prato	NRC

Section B2.1.2, "Infrequently Accessed Area Inspection Activities"

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Section B2.2.1, "Augmented Inspection Activities"

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Sections B2.2.4, "Chemistry Control Program for the Primary Systems"

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Sections B2.2.5, "Chemistry Control Program for Secondary Systems"

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Sections B2.2.7, "Fire Protection Program"

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Section B2.2.9, "General Condition Monitoring Activities"

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Section B2.2.17, "Service Water System Inspections"

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Section B2.2.19, "Work Control Process"

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Attachment 3

License Renewal – Review of NRC Letters
Serial No. 02-277

NRC Letter dated January 30, 2002
Summary of January 28 and 29, 2002 Telecommunication with
Virginia Electric and Power Company

Virginia Electric and Power Company
(Dominion)

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

SERIAL # 02-122

January 30, 2002

RECD FEB 19 2002

NUCLEAR LICENSING

LICENSEE: Virginia Electric Power Company

FACILITIES: North Anna, Units 1 and 2
Surry, Units 1 and 2

SUBJECT: SUMMARY OF JANUARY 28 AND 29, 2002, TELECOMMUNICATION WITH VIRGINIA ELECTRIC POWER COMPANY

On January 28 and 29, 2002, the U.S. Nuclear Regulatory Commission (NRC) staff had a conference call with representatives of Virginia Electric Power Company (VEPCO) to discuss the need for additional clarification regarding information provided in Sections 4.4, and B2.2.3 of the license renewal application. The information requested, the applicant's response, and staff evaluation of the applicant's response is provided in Attachment 1. A list of participants is provided in Attachment 2.

A draft of this phone conversation summary was provided to VEPCO to allow them the opportunity to comment prior to the summary being issued.

Robert J. Prato

Robert J. Prato, Project Manager
License Renewal and Environmental Impacts Program
Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation

Docket Nos. 50-338, 50-339, 50-280, and 50-281

Attachments: As stated

cc w/ atts: See next page

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SUMMARY OF TELECOMMUNICATION WITH
VIRGINIA ELECTRIC AND POWER COMPANY
JANUARY 28 AND 29, 2002

Section 4.4 Environmental Qualification of Electric Equipment

4.4-1 The NRC staff requested that the applicant provide additional description of its data collection methodology used in its Environmental Qualification (EQ) Program.

The applicant provided the following summary regarding data collection that was performed to establish values of temperature, radiation, and mechanical cycles for the EQ Program within the current licensing basis. The applicant states that it is its intent to apply this methodology for data collection, if warranted by changes in plant conditions, during the period of extended operation.

Three types of data are used for the re-evaluation of EQ analyses. The data collection method is described below:

- Temperature Data: Surry Power Station Unit 1 was a pilot plant for life extension. This program began in the mid-1980's. As a part of this program thermocouples were installed in containment to monitor temperature at various locations inside Unit 1 containment. These thermocouples were connected to a data logger located outside containment. In addition, peak recording thermometers were installed in various accessible locations in both Units 1 and 2. Temperatures were collected in areas of known elevated temperatures such as the reactor coolant pump and loop rooms, the pressurizer cubicle, the pipe penetration areas on both sides of the containment wall, areas above the reactor, the main steam valve house, the turbine building, and the auxiliary building. Similar data were collected and analyzed for North Anna. At the conclusion of the life extension pilot project, data collection was continued as an integral part of the EQ Program. The bulk of the temperature data was collected for a period spanning approximately four years. The EQ Group compiled and analyzed the data and documented the results along with the methodology in technical reports for each station. Analysis of the temperature data consisted of compiling and plotting the total duration at specific temperatures versus the measured temperatures. Typical results of the data plots provided a "bell curve" relationship of duration versus temperature. For each temperature plot, a conservatively high temperature was selected to represent the aging temperature in Arrhenius calculations. The conservatively high temperature selected typically represented greater than 95% of the data under the "bell curve."

- Radiation Data: An additional aspect of Surry Power Station's pilot program for life extension included radiation monitoring in select areas inside Unit 1 containment. At the conclusion of the life extension pilot project, the data collection was continued as an integral part of the EQ Program. Radiation monitoring under the pressurizer and in one reactor coolant loop cubicle has continued since 1988. To date, the average dose rate has been 0.7 and 0.9 Rads per hour respectively. These values are approximately 1/40th the design values for the non-accident radiation dose (0.325 Mrads per year or 37 Rads per hour.

- Mechanical Cycles: Mechanical cycles counting is based on a review of operational data, periodic test data and maintenance records to determine the total number of cycles to which a component has been subjected.

The staff found the applicant's response acceptable, and will not need any additional information regarding this matter.

B2.2.3 Boric Acid Corrosion Surveillance

B2.2.3-1 The discussion under "Preventive Actions" in Section B2.2.3 of the LRA states that no preventive actions are performed. The recommendations of GL 88-05 include preventive actions and it appears that preventive actions are included in this AMP. The following information is needed:

a. It is the staff's understanding that the Boric Acid Corrosion Surveillance program will prevent or mitigate boric acid corrosion by frequent monitoring of the locations where potential leakage could occur and timely repair if leakage is detected. The applicant is requested to confirm the staff's understanding of this AMP and to provide an explanation as to why such activities under the program are not considered to be preventive actions.

The applicant responded that the boric acid corrosion surveillance activities are performed at the beginning of each refueling outage, or when the calculation of primary system leakage rate, that is required by Technical Specifications, indicates an increased level of unidentified leakage. If indications of leakage are found, the boric acid residue is removed, the cause of the leakage is determined, and repairs are implemented in accordance with the Corrective Action System. Operating experience confirms that leakage is discovered and corrected prior to a loss of intended function. In this way, Boric Acid Corrosion Surveillance is considered to be a preventive action.

The staff found the applicant's response acceptable, and will not need any additional information regarding this matter.

b. GL 88-05 recommends that corrective actions to prevent recurrence of boric acid corrosion should include modifications in the design or operating procedures to reduce the probability of leaks at locations where they may cause corrosion damage and use of suitable corrosion resistant materials or the application of protective coatings or claddings. Based on Dominion's operating experience with the Boric Acid Corrosion Surveillance program, discuss the extent to which the above recommendations have been implemented at all four units. If these recommendations have not been implemented, explain why not.

The applicant responded that the design of the plant includes the use of corrosion-resistant stainless steel for components that are intended to come into contact with boric acid. Carbon-steel components that may be contacted by boric acid leakage are covered with protective coatings, except for bolting. Operating experience with respect to the Boric Acid Corrosion Surveillance program confirms that leakage is discovered and corrected prior to a loss of intended function. This statement also is true for the uncoated bolting which includes a sufficient amount of material for each bolt, and a conservative number of bolts, to ensure that intended function is not lost.

Operating experience has shown that when boric acid leakage does occur, it is typically observed at valve packings and bolted flanges, and is corrected by maintenance tasks. No occurrences of boric acid leakage have necessitated design changes or modifications of operating procedures. Maintenance procedures allow only minimal adjustment of valve packing before a packing replacement is required in order to correct any leakage. Since the same maintenance procedures are used for valve packings and flanges throughout the plant, the randomness of the relatively small number of leakage locations that are found at the beginning of refueling outages confirms the appropriateness of the current maintenance practices. It is typical during a refueling outage boric acid corrosion walkdown to not find active leaks but, instead, walkdowns will more likely find boric acid residue as a result of the previous plant heatup process.

The staff found the applicant's response acceptable, and will not need any additional information regarding this matter.

Attendance list
Telephone Conference Call Virginia Electric Power Company (VEPCO)
January 28 and 29, 2002

Name	Organization
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Robert Prato	NRC/NRR
Michael Henig	VEPCO
Paul Aitkens	VEPCO
Tom Snow	VEPCO
Michael Pinion	VEPCO
Marc Hotchkiss	VEPCO
Dave Hostetler	VEPCO
Preston Doughtery	VEPCO

Attachment 2