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SOUTHERN COMPANY
Energy to Serve Your World℠

April 16, 2004

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NL-04-0617

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

Joseph M. Farley Nuclear Plant Units 1 and 2
Application for License Renewal –
Requests for Additional Information

Ladies and Gentlemen:

This letter is in response to your letter dated March 17, 2004 requesting additional information for the review of the Joseph M. Farley Nuclear Plant, Units 1 and 2, License Renewal Application. Responses to the Requests for Additional Information (RAIs) are provided in Enclosure 1.

Also provided in this letter is supplemental information for the following items:

1. RAI 4.3.4-1 on Containment Building Tendon Prestress
2. RAI 2.1-1 on 10CFR54.4(a)(2) methodology

(Affirmation and signature are on the following page.)

A099

Mr. L. M. Stinson states he is a vice president of Southern Nuclear Operating Company, is authorized to execute this oath on behalf of Southern Nuclear Operating Company and to the best of his knowledge and belief, the facts set forth in this letter are true.

If you have any questions, please contact Charles Pierce at 205-992-7872.

Respectfully submitted,

SOUTHERN NUCLEAR OPERATING COMPANY

L. M. Stinson
Vice President, Farley

Sworn to and subscribed before me this 16th *day of* April, *2004.*

Gloria H. Bure
Notary Public

My commission expires: 6-7-05

LMS/JAM/slb

Enclosures: 1. Responses to March 17, 2004 Requests for Additional Information, Joseph M. Farley Nuclear Plant, Units 1 and 2
2. Supplemental Information for Previously Submitted RAI Responses

cc: Southern Nuclear Operating Company
Mr. J. B. Beasley Jr., Executive Vice President
Mr. D. E. Grissette, General Manager – Plant Farley
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U. S. Nuclear Regulatory Commission
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Mr. L. A. Reyes, Regional Administrator
Mr. S. E. Peters, NRR Project Manager – Farley
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Alabama Department of Public Health
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ENCLOSURE 1

Joseph M. Farley Nuclear Plant Units 1 and 2

Application for License Renewal

Responses to March 17, 2004 Requests for Additional Information

RAI 3.0-1

The following questions are CONFIRMATORY and CLARIFICATION (C/C) in nature. The corresponding draft RAI number associated with each question is indicated in parenthesis.

A. (D-RAI 3.1-3)

In LRA Table 3.1.2-3, the ISI program is not credited to manage cracking of non-Class 1 piping and valve components. However, LRA summary Table 3.1.1, item 3.1.1-36 (linked to the non-class 1 piping and valve bodies) states:

> "The FNP AMR results are consistent with this summary item. Consistent with NUREG-1801, the Water Chemistry Program and Inservice Inspection Program will manage cracking of these components."

There is an apparent inconsistency between the two Tables of the LRA. Please explain whether the ISI program is credited for the non-class 1 piping and valve bodies and, if necessary, correct the apparent inconsistency.

Response

The ISI Program is not credited to manage cracking of non-Class 1 piping and valve components. For clarity, the second paragraph of the discussion text contained in FNP LRA Table 3.1.1, Item 3.1.1-36 should have read as follows: (***Insertions in bold italics.***)

While the Water Chemistry Control Program and the Inservice Inspection Program are credited, Inservice Inspection for this group is primarily directed at welded connections ***in ASME Class 1 components.*** The Water Chemistry Control Program alone will manage cracking of the non-welded portions of ***ASME Class 1*** components/component types within this group ***and all non ASME Class 1 components/component types within this group.***

RAI 3.0-1 (continued)

The following questions are CONFIRMATORY and CLARIFICATION (C/C) in nature. The corresponding draft RAI number associated with each question is indicated in parenthesis.

B. (D-RAI 3.4-4)

LRA Table 3.4.2-1 identifies no aging effects for alloy steel steam/fluid traps in an outside environment. The LRA defines an outside environment as: "An environment where components are exposed to direct sunlight, precipitation, and freezing conditions. The outside environment also conservatively includes components located in sheltered areas where the component is beneath some type of roof structure or outdoor enclosure (such as a valve box) but is otherwise open to the ambient environment." The GALL report recommends aging management for the loss of material due to general corrosion on the external surfaces of carbon (alloy) steel components exposed to operating temperatures less than 212°F, such corrosion may be due to air, moisture, or humidity. The applicant is requested to provide a program to manage corrosion on the external surface of alloy steel steam/fluid traps in an outside environment or to provide justification for not managing this aging effect.

Response

The LRA Table 3.4.2-1 line item for alloy steel steam/fluid traps in an outside environment identifies no external aging effects because these components are exposed to operating temperatures of greater than 212°F, as shown by this line item being annotated with Plant Specific Note 21. Plant Specific Note 21 states: "With the exception of boric acid corrosion, external surfaces of carbon and alloy steel components that operate at high temperature are not susceptible to loss of material."

These steam/fluid traps are located in the Main Steam Valve Room (MSVR). The MSVR is a vented room in the Auxiliary Building and therefore is a sheltered environment. The MSVR is covered by a roof, but the walls are made from grating. Components in the MSVR are therefore exposed to outside air, but are sheltered from rain.

There is no source of borated water leakage in the area of these components. Since these traps operate at high temperature, and there is no potential for boric acid corrosion, there are no external aging effects.

RAI 3.0-1 (continued)

The following questions are CONFIRMATORY and CLARIFICATION (C/C) in nature. The corresponding draft RAI number associated with each question is indicated in parenthesis.

C. (D-RAI 3.5-6)

Regarding the AMR summary covering FNP's sump trash rack listed on Table 3.5.2-1 (page 3.5-38) of the LRA, the applicant identified no applicable aging effect as well as AMP for the stainless steel component. Since sumps tend to be exposed to high moisture, acidic or accumulated water environment, discuss FNP's past operating/inspection experience covering sump trash racks to support its AMR finding that no AMP is needed for the component.

Response

The sump trash rack listed on Table 3.5.2-1 represents the screen-grating assemblies that protect the pump intakes from debris that could be drawn into the pump suction lines during post-accident recirculation mode operation of the Emergency Core Cooling System (ECCS) and Containment Spray System. Information on the containment recirculation sump, also referred to as the containment emergency sump, is provided in UFSAR Appendix 6C.

The containment emergency sump is not a typical sump that is below floor level and accumulates drainage, leakage, etc. Each ECCS and Containment Spray pump intake line penetrates the containment floor with no trench or traditional sump feature provided. The sump trash rack assemblies are attached directly on top of the floor slab and are not depressed below the floor elevation. During normal modes of operation this area is dry. The environment, as indicated in the LRA, is "Inside." FNP and industry operating experience indicates that stainless steel in an "Inside" environment is not subject to aging, therefore no aging management program is required.

Inspections of the containment emergency sumps support this conclusion. Although not credited for License Renewal, the sump trash rack assemblies are inspected as part of the Structural Monitoring Program with no findings to date. Detailed inspections performed in 1997 in response to IN 96-10 did not identify any aging-related degradation. In conclusion, FNP's operating experience supports SNC's AMR finding that no AMP is needed for the containment emergency sump trash rack assemblies.

RAI 3.0-1 (continued)

The following questions are CONFIRMATORY and CLARIFICATION (C/C) in nature. The corresponding draft RAI number associated with each question is indicated in parenthesis.

D. (D-RAI 3.5-11)

In Item 3.3.1-11 (Table 3.3.1), the applicant states that the FNP new fuel storage racks are fabricated from both carbon steel (CS) and stainless steel (SS). Chapter VII of NUREG 1801 does not address such hybrid rack configurations. Depending on the CS-SS interface between the racks, stress corrosion cracking of the SS portion of the racks cannot be ruled out. The applicant is requested to provide justification for not requiring aging management of the SS portion of the new fuel storage racks.

Response

The FNP new fuel storage racks are designed such that all surfaces contacting the new fuel are constructed from stainless steel. Stainless steel portions of the racks are bolted to a painted carbon steel support structure. These racks are located in the controlled "Inside" environment of the Auxiliary Building, which is not an aggressive environment. These racks are not submerged or otherwise exposed to a wetted environment. Additionally, these racks are subject only to ambient indoor temperatures.

Since there is no significant source of contaminants (principally chlorides for stainless steels) and the racks are located in the mild environment of the Auxiliary Building, stress corrosion cracking of the stainless steel portions of the FNP new fuel racks is not a valid aging mechanism.

RAI 4.0-1

The following question is CONFIRMATORY and CLARIFICATION (C/C) in nature. The corresponding draft RAI number associated with each question is indicated in parenthesis.

A. (D-RAI 4.3.2.2-1)

The staff needs further clarification as to the number of reactor coolant pump (RCP) start/stop cycles that are assumed in the 60-year RCP flywheel fatigue crack growth assessment for the Farley units. In Section 4.3.2 of the Farley license renewal application (LRA), Southern Company states that 4000 RCP start/stop cycles are assumed in the analysis. However, in Southern Company's letter of December 5, 2003, Southern Company states that 6000 RCP start/stop cycles are assumed for the bounding 60-year RCP flywheel fatigue crack growth assessment. Clarify the number of start/stop cycles assumed for the bounding 60-year RCP flywheel fatigue crack growth assessment and which reference (WCAP Topical Report) contains the 60-year RCP flywheel fatigue crack growth analysis for the Farley units.

Response

WCAPs 14535A and 15666 are the most recent RCP flywheel fatigue crack growth assessments for FNP. They both assume 6000 RCP start/stop cycles over a 60 year life. The statement in Section 4.3.2 of the Farley LRA that 4000 RCP start/stop cycles are assumed in the analysis was incorrect. SNC's conclusion that the number of cycles assumed in the calculation is bounding for 60 years remains the same.

RAI B-1

The following question is CONFIRMATORY and CLARIFICATION (C/C) in nature. The corresponding draft RAI number associated with each question is indicated in parenthesis.

A. (D-RAI B.5.2-2)

SNC's AMP description for the Flux Detector Thimble Inspection Program implies that SNC may use alternative inspection methods for the thimble tubes examinations in lieu of ECT but did not define which inspection methods might be used as an alternative to ECT. The staff therefore requests that, if alternative inspection methods are used in lieu of ECT, the applicant provide further clarification regarding the inspection methods that will be used for the flux thimble examinations and how the alternative inspection methods, if used, will be qualified as being capable of detecting loss of material/wear in the flux thimble tubes.

Response

Eddy current testing (ECT) is the technique currently used to determine the amount of wear on flux thimble tubes. Other volumetric examination techniques are not currently credited as alternatives to eddy current testing. If other volumetric examination techniques become available in the future, SNC reserves the option to revise the Flux Detector Thimble Inspection Program to perform inspections using qualified techniques. SNC will continue to participate in Westinghouse Owner's Group (WOG) activities related to flux detector thimble inspection. When issued, any WOG recommended actions, including changes to qualified inspection methods, will be reviewed and the Flux Detector Thimble Inspection Program modified, as appropriate. This is consistent with the November 2, 1988 response to NRC Bulletin 88-09 for FNP.

RAI 3.1.3.1.1-1

a. The staff requires additional information on the applicant's AMRs for managing loss of material in the NiCrFe components and stainless steel components that are exposed to borated water environment, particularly since aging management strategies for license renewal are more dependent of the specific types of aging mechanisms that can induce age-related degradation and to a lesser degree on the general classification of the aging effect (in this case loss of material). For the components listed within the scope of this RAI, confirm that loss of material is an applicable aging effect requiring aging management. Specifically, for each NiCrFe or stainless steel component or commodity group that is identified below as being within the scope of this RAI and for which loss of material has been confirmed to be an applicable aging effect, define which aging mechanism or mechanisms are known to induce loss of material in the specific components or commodity group of components. This RAI is applicable to the following commodity group components in LRA Tables 3.1.2-1, 3.1.2-2, and 3.1.2-3 that have corresponding AMRs for evaluating loss of material under internal exposure to the borated water environment:

Table 3.1.2-1, Reactor Coolant Systems, Reactor Vessel - Summary of Aging Management Review

- bottom head torus and dome (low alloy steel with stainless steel cladding)
- bottom mounted instrumentation guide tubes (stainless steel)
- bottom mounted instrumentation penetrations (Alloy 600, a NiCrFe alloy)
- core exit thermocouple (CET) and heated junction thermocouple closure (HJTC) assemblies (stainless steel)
- closure head dome and flange (low alloy steel with stainless steel cladding)
- RV core support lugs (Alloy 600, a NiCrFe alloy)
- control rod drive mechanism (CRDM) and instrumentation housing penetration nozzles (thermally treated Alloy 690, a NiCrFe alloy)
- CRDM housing flange adapters (stainless steel)
- CRDM latch housings and rod travel housings (stainless steel)
- RV head vent penetration (thermally treated Alloy 690, a FeNiCr alloy)
- intermediate and lower shell courses (low alloy steel with stainless steel cladding)
- RV leakage monitoring tube assembly (Alloy 600, a NiCrFe alloy)
- RV primary nozzle safe end (stainless steel with Alloy 82/182 welds and buttering, NiCrFe weld filler metals)
- vessel flange (alloy steel with stainless steel cladding)
- seal table and fittings (stainless steel)
- upper (nozzle) shell course (low alloy steel with stainless steel cladding)
- stainless steel cladding for the alloy steel or carbon steel RV components that are clad with austenitic stainless steel

Table 3.1.2-2, Reactor Coolant Systems, Reactor Vessel Internals - Summary of Aging Management Review

- baffle and former plates (stainless steel)
- baffle bolts (stainless steel)
- Bottom mounted instrumentation (BMI) column cruciforms (cast austenitic stainless steel or CASS)

- BMI columns with fasteners (stainless steel)
- clevis inserts and fasteners (FeNiCr Alloy - Alloy 600 inserts and Alloy X-750)
- control rod drive guide tube assemblies with associated fasteners (stainless steel)core barrel and core barrel flange (stainless steel)
- core barrel outlet nozzles (stainless steel)
- control rod drive guide tube (CRGT) support pins (stainless steel)
- flux thimble tubes (stainless steel)
- reactor pressure vessel / head alignment pins with associated fasteners (stainless steel)
- head cooling spray nozzles (stainless steel)
- HJTC probe holder, probe holder extension, and probe holder shroud assemblies with associated fasteners (stainless steel)
- internals holddown spring (stainless steel)
- lower core plate and fuel alignment pins (stainless steel)
- lower support columns with associated fasteners (stainless steel)
- lower support forging (stainless steel)
- neutron panels (stainless steel)
- radial keys and fasteners (stainless steel)
- secondary core support assembly with associated fasteners (stainless steel)
- upper core alignment pins with associated fasteners (stainless steel)
- upper core plate and fuel alignment pins with fasteners (stainless steel)
- upper instrumentation conduit and supports with associated fasteners (stainless steel)
- upper support assembly with associated fasteners (stainless steel)
- upper support column bases (stainless steel)
- upper support column with associated fasteners (stainless steel)

Table 3.1.2-3, Reactor Coolant Systems, Reactor Coolant System and Connected Lines - Summary of Aging Management Review

- Class 1 piping - reactor coolant loop (cast austenitic stainless steel)
- small bore Class 1 piping less than 4 NPS (stainless steel)
- Class 1 piping greater than or equal to 4 NPS (stainless steel)
- Class 1 valve bodies (stainless steel)
- Class 1 flow orifices or elements (stainless steel)
- Reactor Coolant Pump (RCP) casing (CASS)
- RCP main closure flange (CASS)
- pressurizer heater sheaths (austenitic stainless steel)
- pressurizer instrumentation nozzle and heater well nozzles (stainless steel)
- pressurizer manway and cover (alloy steel with stainless steel insert)
- pressurizer nozzle safe ends (stainless steel with alloy 82/182 welds and buttering, NiCrFe weld filler metals)
- pressurizer surge, spray, safety, and relief nozzles (alloy steel with stainless steel cladding)
- pressurizer shell, upper head, and lower head (alloy steel with stainless steel cladding)
- pressurizer spray head assembly (CASS)
- pressurizer surge and spray nozzle thermal sleeves (stainless steel with alloy 82/182 welds, NiCrFe weld filler metals)
- Non-Class 1 RCS piping (stainless steel)
- Non-Class 1 valve bodies (stainless steel)

Response

SNC confirms that loss of material is an aging effect requiring management for all of the components listed by RAI 3.1.3.1.1-1a.

For all of the component types listed by RAI 3.1.3.1.1-1a, crevice corrosion and pitting are loss of material aging mechanisms that are conservatively considered by FNP in the borated water environment. The following additional loss of material aging mechanisms are applicable to specific component types from the list:

1. SNC conservatively assumed loss of material due to wear to be an aging effect requiring management for the following component types included in the RAI 3.1.3.1.1-1a component type list:

    - Vessel Flange
    - Clevis Inserts and Fasteners
    - Flux Thimble Tubes
    - Internals Holddown Spring
    - Radial Support Keys and Fasteners
    - Upper Core Plate Alignment Pins

2. SNC conservatively assumed loss of material due to erosion to be an aging effect requiring management for the Pressurizer Spray Head.

RAI 3.1.3.1.1-1

b. With the exception of AMPs credited for management of loss of material in the RV flange, incore flux thimble tubes, reactor vessel (RV) internals holddown spring, RV internals radial keys and fasteners, and pressurizer spray head assembly, the applicant credits only the Water Chemistry Program as the aging management program for management of loss of material in the RV, RV internals, pressurizer, and RCS piping and connected system components listed within the scope of RAI 3.1.3.1.1-1a. Justify why SNC considers that the Water Chemistry Program alone is sufficient to manage loss of material in these components without the need to credit an inspection-based AMP to verify that the Water Chemistry Program is accomplishing its mitigative aging management function. The applicant is requested to discuss how the implementation of the Water Chemistry Program relates to management of the specific aging mechanisms that are identified as being capable of inducing loss of material in the components. If the technical assessments (justifications) conclude that the Water Chemistry Program alone is insufficient to manage all of the aging mechanisms leading to loss of material in any of these components, propose acceptable inspection-based AMP for management of loss of material that is applicable to the specific RV, RV internal, RCS piping or pressurizer component.

Response

In the LRA, the FNP Water Chemistry Control Program (alone) is credited to manage loss of material due to the aging mechanisms of crevice corrosion and pitting for all of the components listed by RAI 3.1.3.1.1-1a. Our rationale follows.

The wetted surfaces (borated water environment) of the components identified in 3.1.3.1.1-1 are fabricated from stainless steel and NiCrFe alloys. For stainless steels and NiCrFe alloys, penetration of the passive chromium oxide layer and subsequent corrosion has been shown to be principally related to the oxidizing nature of the environment and the presence of specific detrimental ionic species known to interfere with the passivation process; most notably chlorides, sulfates, and fluorides.

The FNP Water Chemistry Control Program is implemented consistent with the EPRI Primary Water Chemistry Guidelines. This industry guideline is the result of extensive industry operating experience, research, and industry consensus. The resulting program provides for both a strongly reducing coolant environment via the addition of oxygen scavengers such as hydrogen and for strict control of ionic species. A sufficient residual concentration of hydrogen is maintained at all times to assure the reducing nature of the reactor coolant. Detrimental ionic species such as chlorides, sulfates, and fluorides are limited to the low ppb range during power operations.

FNP and industry wide operating experience confirm that pitting and crevice corrosion has not been an issue of concern for reactor coolant system components. FNP inservice inspections performed in accordance with Section XI of the ASME Code include numerous inspection locations consisting of the borated water environment and stainless steel and NiCrFe alloy material combinations.

The aging effects determinations in NUREG-1801 also support this position. NUREG-1801 acknowledges that loss of material due to pitting and crevice corrosion is not an

aging effect/mechanism requiring management for stainless steel components exposed to a borated water environment. Specifically, several sections of NUREG-1801 (e.g., sections V.D1, VII.A3, VII.E1) include a conclusive statement that stainless steel components are not subject to significant general, pitting, and crevice corrosion in a borated water environment; therefore these aging mechanisms are not included in NUREG-1801 for this material and environment combination. In addition, SNC has not identified any NUREG-1801 recommendation for an inspection-based AMP to manage loss of material due to pitting and crevice corrosion for stainless steel and NiCrFe alloys in a borated water environment.

RAI 3.1.3.1.2-1

a. In Tables 3.1.2-1 and 3.1.2-3 of the Farley LRA, SNC did not identify the aging mechanisms that it determined to be capable of inducing loss of material in reactor vessel (RV), RCS piping, and pressurizer components fabricated from alloy steel or carbon steel materials. Therefore, the staff requests that SNC identify the aging mechanisms that SNC has determined are capable of inducing loss of material in alloy steel or carbon steel RV, RCS piping, or pressurizer components that are exposed externally to the inside environments. In addition, SNC's description of the inside environment in Table 3.0.4-2 of the Farley LRA does not indicate that the applicant is managing the water vapor content in the inside environment to low humidity levels. Provide clarification as to whether the applicant considers loss of material due to general corrosion is an applicable aging effect for external surfaces of alloy steel or carbon steel RV, RCS piping, and pressurizer components that are exposed to the inside environment, and if not, provide the technical basis as to why SNC does not consider general corrosion to be an aging mechanism that needs management in the external surfaces of alloy steel or carbon steel RV, RCS piping, and pressurizer components during the extended periods of operation for Farley Nuclear Plant, Units 1 and 2. This RAI is applicable to the following commodity group components in LRA Tables 3.1.2-1 and 3.1.2-3 that have corresponding AMRs for evaluating loss of material under external exposure to the inside environment:

Table 3.1.2-1, Reactor Coolant Systems, Reactor Vessel - Summary of Aging Management Review

- bottom head torus and dome (alloy steel with stainless steel cladding)
- closure head dome and flange (alloy steel with stainless steel cladding)
- RV closure studs, nuts, and washers (alloy steel)
- intermediate and lower shell courses (alloy steel with stainless steel cladding)
- primary inlet and outlet nozzles and nozzle support pads (alloy steel with stainless steel cladding)
- refueling seal ledge (carbon steel)
- vessel flange (alloy steel with stainless steel cladding)
- upper (nozzle) shell course (alloy steel with stainless steel cladding)
- ventilation shroud support ring (carbon steel)

Table 3.1.2-3, Reactor Coolant Systems, Reactor Coolant System and Connected Lines - Summary of Aging Management Review

- Class 1 closure bolting (alloy steel)
- reactor coolant pump (RCP) main flange bolting (alloy steel)
- pressurizer closure bolting (alloy steel)
- pressurizer manway cover (alloy steel with a stainless steel insert)
- pressurizer nozzles (surge, spray, safety and relief nozzles - low alloy steel with stainless steel cladding)
- pressurizer shell, upper head, and lower head (alloy steel with stainless steel cladding)

Response

Loss of material due to boric acid wastage is considered to be an aging effect requiring management in an inside environment for external surfaces of the carbon steel and alloy steel reactor coolant system components listed in RAI 3.1.3.1.2-1a. Also, loss of material due to wear is an aging effect requiring management for the RV closure studs, nuts, and washers component type.

SNC does not consider loss of material due to general corrosion to be an aging effect requiring management in an inside environment for the external surfaces of the carbon steel and alloy steel reactor coolant system components listed in RAI 3.1.3.1.2-1a. The continued presence of moisture is required to sustain significant general corrosion of carbon steel and alloy steel components. These components operate at temperatures well above 212 °F. The bare metal exterior surface temperatures are significantly higher than the ambient temperature, therefore no condensation would occur on these surfaces and any moisture or leakage will be evaporated by the high surface temperatures.

RAI 3.1.3.1.2-1

b. In the Farley LRA, the SNC credited only the Borated Water Leakage Assessment and Evaluation Program with the management of loss of material from the external surfaces of the alloy steel or carbon steel RV components that are exposed to the inside environment. In RAI 3.1.3.1.2-1a, the staff requested additional information regarding the aging mechanisms that could induce loss of material from the external surfaces of alloy steel and carbon steel RV, RCS piping, and pressurizer components under exposure to inside environments. The staff therefore requests additional information (a technical basis) why SNC considers that the Borated Water Leakage Assessment and Evaluation Program alone is sufficient to manage loss of material in external surfaces of the alloy steel and carbon steel RV, RCS piping, and pressurizer components within the scope of RAI 3.1.3.1.2-1a, and particularly if the "loss of material" aging effect is known to be induced by aging mechanisms other than "boric acid-leakage and boric acid-induced wastage." If the "loss of material" aging effect is known to be induced by aging mechanisms other than "boric acid-leakage and boric acid-induced wastage," the staff requests that SNC credit additional aging managment programs or activities with management of the "loss of material" aging effect if the "Borated Water Leakage Assessment and Evaluation Program" is determined to be insufficient to assure adequate aging management of the "loss of material" aging effect during the extended periods of operation for the Farley units.

Response:

Except for loss of material due to wear in RPV closure studs (see response to RAI 3.1.3.1.2-1a), SNC concluded that boric acid wastage is the only significant potential contributor to loss of material for the external surfaces of the alloy steel and carbon steel RV, RCS piping, and pressurizer components listed. As described in the response to part (a) of this RAI, loss of material due to general corrosion is not considered to be an aging effect/mechanism requiring management for external surfaces of carbon steel and alloy steel components listed in RAI 3.1.3.1.2-1a exposed to an inside environment since they operate at high temperatures.

RAI 3.1.3.2.1-1

In the staff's aging management review (AMR) for Commodity Group IV.B2.6-c of the GALL Report, Volume 2, the staff recommends that both a "plant-specific" aging management program (AMP) and the ASME Section Inservice Inspection, Subsections IWB, IWC, and IWD Program be credited with management of loss of material due to wear in flux detector thimble tubes. The applicant has credited both the Flux Detector Thimble Inspection Program (i.e., a "plant-specific" AMP) and the Water Chemistry Program with aging management of wear in the Farley flux detector thimble tubes. SNC did not credit the ISI Program for management of loss of material due to wear in the flux detector thimble tubes at Farley. Although SNC has credited the Flux Detector Thimble Inspection Program with management of loss of material due to wear in the flux detector thimble tubes, the applicant is requested to provide the technical basis for not crediting the ISI Program as an additional AMP for management of this aging effect in the thimble tubes, as would otherwise be consistent with the staff recommendations in GALL Commodity Group IV.B2.6-c.

Response

SNC credits only the Flux Detector Thimble Inspection Program with management of loss of material due to wear in FNP's flux detector thimble tubes. A review of recent license renewal applicants indicates the SNC approach is consistent with approach of recent applicants (Catawba/McGuire, Robinson, Turkey Point, Ginna, North Anna, and Summer) that have been accepted by the Staff.

ASME Section XI Code methods that could detect wear in the tubes (e.g., volumetric and/or surface examinations) are not applicable under the Code. The ASME Section XI Code exempts small diameter piping and tubing (except for steam generator tubing) from volumetric and surface examination requirements. The diameter of FNP's flux detector thimble tubes is 0.210 ± 0.003" ID in Unit 1, and 0.201 ± 0.003" ID in Unit 2.

Based on extensive industry operating experience, the volumetric examinations performed in accordance with the Flux Detector Thimble Inspection Program are adequate to detect loss of material due to wear in flux thimble tubes prior to loss of tube integrity.

RAI 4.2.1.3-1

Pursuant to 10 CFR Part 54.21(d), the FSAR Supplement for a facility license renewal application (LRA) must contain a summary description for each aging management program and time-limited aging analysis proposed for management of the effects of aging. The staff has determined that Appendix A of the LRA (FSAR Supplement) did not include a corresponding FSAR Supplement summary description for the TLAA in Section 4.2.1, "Neutron Fluence," of the LRA. The staff recognizes that the licensee calculated fluence values to 54 EFPYs (i.e., the end of the requested license extension). However, the operating assumptions in these calculations could change as for example with the introduction of new fuel, new material properties, etc. In such an instance 10 CFR 50.61 and other regulations requires recalculation of the fluence and reevaluation of the material properties. Therefore it is necessary to capture this information in the FSAR Supplement. Pursuant to 10 CFR 54.21(d), the staff requires that a corresponding FSAR Supplement summary description for LRA Section 4.2.1 be included in the FSAR Supplement.

Response

The neutron fluence calculations are captured in the applicable WCAPs and are summarized for critical components in the Pressure and Temperature Limits Reports (PLTRs) for the respective units. The FNP FSAR Supplement will be revised to include the following:

A.4.1.5 Neutron Fluence Calculation

SNC updated the reactor vessel neutron embrittlement calculations including the neutron fluence calculations for the critical components of the reactor vessel for 54 EFPY in accordance with 10 CFR 54.21(c)(1)(ii). The neutron fluence values that apply for the current operating conditions at FNP are summarized in the Pressure and Temperature Limits Report (PTLR) for each unit. When the PTLR is updated to include P-T limit curves that bound the current level of neutron embrittlement for the unit, changes in neutron fluence values are included.

RAI 4.2.3.3-1

The applicant's FSAR Supplement summary description for the time-limited aging analysis of pressurized thermal shock (i.e., TLAA for PTS), is described in Section A.4.1.2 of the application. The limiting RT_{PTS} value cited by the applicant for Farley Unit 2 in the FSAR Supplement summary description (i.e., 193°F) is not consistent with the limiting RT_{PTS} value cited in Table 4.2.3-2 of the LRA (i.e., 208°F, based on Intermediate Shell Plant B7212-1). The staff requests that SNC revise the limiting RT_{PTS} value cited in the FSAR Supplement A.4.1.2 for Farley Unit 2 to be consistent with the limiting RT_{PTS} value reported in Table 4.2.3-2 of the LRA (i.e., 208°F).

Response

The RT_{PTS} value cited for Farley Unit 2 in the FSAR Supplement summary description (i.e., 193°F) is incorrect and will be corrected to agree with the value in Table 4.2.3-2 of the application (i.e., 239°F) as shown below (change denoted by ***bold italics***).

A.4.1.2 Pressurized Thermal Shock (PTS) Calculation

The requirements of 10 CFR 50.61 provide for protection against pressurized thermal shock events in pressurized water reactors. The screening criterion in § 50.61 is 270 °F for plates, forgings, and axial welds and 300 °F for circumferential welds. According to this regulation, if the calculated RT_{PTS} for the limiting reactor beltline materials is less than the specified screening criterion, then the vessel is acceptable with regard to the risk of vessel failure during postulated pressurized thermal shock transients.

SNC has updated the RT_{PTS} calculations for FNP Units 1 and 2 to include the period of extended operation, and has determined that the screening criteria are met for both units. The limiting material for FNP Unit 1 has a 54 EFPY RT_{PTS} value of 191°F. The limiting material for FNP Unit 2 has a 54 EFPY RT_{PTS} value of ***239°F***. These TLAAs have been shown to be acceptable for the period of extended operation in accordance with 10CFR 54.2(c)(1)(ii).

RAI 4.2.4.2-1

The limiting 1/4T and 3/4T adjusted reference temperature values (i.e, RT_{NDT} values) for the reactor vessel (RV) beltline materials in operating reactors are used in the calculations of pressure-temperature (P-T) limits, which are calculated under the scope of the requirements of Section IV.A.2 to 10 CFR Part 50, Appendix G. The applicant did not provide the 3/4T RT_{NDT} values for the limiting 3/4T beltline materials in the RVs of Farley, Units 1 and 2. The staff requests that the applicant supplement the discussion in Section 4.2.4 of the LRA to provide the 3/4T RT_{NDT} values for the limiting 3/4T beltline materials in the reactor vessels of Farley, Units 1 and 2, through 54 EFPY of operation.

Response

The ¾T adjusted reference temperature (ART) values for the limiting ¾T beltline materials in the RVs of Farley, Units 1 and 2 are:

FNP Unit 1: Lower Shell Plate B6919-1 with an ART of 159 °F at ¾T.

FNP Unit 2: Intermediate Shell Plate B7212-1 with an ART of 163 °F at ¾T.

RAI 4.2.4.3-1

The applicant did not include an FSAR Supplement summary description for SNC's TLAA on the calculation of the adjusted reference temperature values (RT_{NDT} values) for the RV beltline materials at the 1/4T and 3/4T locations of the Farley RVs. Since SNC has defined these adjusted reference temperature calculations as TLAAs in Section 4.2.4 of the LRA, the applicant is required by 10 CFR 54.21(d) to include an FSAR supplement summary description for the applicant's calculation of the adjusted reference temperature values (RT_{NDT} values) for the RV beltline materials at the 1/4T and 3/4T locations of the Farley RVs. The staff requests that SNC amend the Farley license renewal application to include an FSAR Supplement summary description for the TLAA (Section 4.2.4 of the application) on the calculation of the adjusted reference temperature values (RT_{NDT} values) for the RV beltline materials at the 1/4T and 3/4T locations of the Farley RVs.

Response

The FNP FSAR Supplement will be revised to include the following:

A.4.1.4 Adjusted Reference Temperature (ART) Calculation

SNC updated the calculations to determine the adjusted reference temperature (ART) for the critical components of the reactor vessel for 54 EFPY in accordance with 10 CFR 54.21(c)(1)(ii). The ART values that apply for the current operating conditions at FNP are included in the Pressure and Temperature Limits Report (PTLR) for each unit. When the PTLR is updated to include P-T limit curves that bound the current level of neutron embrittlement for the unit, updated ART values are included.

RAI 4.5.1-1

Section 4.5.1 "Ultimate Heat Sink Silting" of the FNP LRA states that the applicant has updated the design calculations pertaining to the surveillance of the Ultimate Heat Sink (UHS) to address silting induced aging. It is further stated that this update addresses the UHS silting issue for the additional 20 years of operations in the extended term in accordance with 10 CFR 54.21(c)(1)(ii). In order to complete the review of the UHS silting issue at FNP site, the staff needs the following additional information:

a. Provide the UHS pond volume surveillance data from all the available sounding measurement records to date. (Raw sounding measurements data are not required).

Response

The data from the UHS pond surveillances appears in the table below. Additional data has been taken since the cut-off date for processing the application (as discussed in Section 2.1.2 of the LRA). The table includes data taken in August of 2003.

Year	Volume (acre-ft)	Surface Area (sqft)	Surface Area (acres)
1981	1,412	4,142,573	95.1
1982	1,416	N/A	N/A
1983	1,430	N/A	N/A
1984	1,403	N/A	N/A
1985	1,440	4,130,930	94.8
1986	1,416	4,127,000	94.7
1987	1,416	4,128,000	94.8
1988	1,415	4,083,240	93.7
1989	1,407	4,097,720	94.1
1993	1,425	4,128,203	94.8
1998	1,434	4,049,819	93.0
2003	1,408	4,113,806	94.4

RAI 4.5.1-1

Section 4.5.1 "Ultimate Heat Sink Silting" of the FNP LRA states that the applicant has updated the design calculations pertaining to the surveillance of the Ultimate Heat Sink (UHS) to address silting induced aging. It is further stated that this update addresses the UHS silting issue for the additional 20 years of operations in the extended term in accordance with 10 CFR 54.21(c)(1)(ii). In order to complete the review of the UHS silting issue at FNP site, the staff needs the following additional information:

b. Provide the rate of siltation of the UHS pond that was observed in the past based on the periodic surveillance measurements made thus far. Also address the applicability of this measured rate to the remaining years of the current license period and the extended period of operation (i.e., are there any known future changes in the hydrology of the river likely to increase significantly sediment intake?)

Response

The original calculation (prior to updating for license renewal) used the sounding data taken in the years from 1981 to 1989 to predict the 40 year end-of-life volume in the ultimate heat sink (UHS). The calculation used a linear regression analysis and the method of least squares to plot a line through the data points. The slope of this line is a method to estimate the siltation rate. The slope of the line for the original calculation implied a siltation rate of 0.6333 acre-feet per year, however the correlation between the line and the data (-0.15) indicates that the line and the data do not correlate well. As a result, the predicted 40 year end-of-life (EOL) volume in the UHS was reduced by 5% to 1325 acre-feet in the calculation. The 1325 acre-feet value is used in the evaluation of the service water pond as the ultimate heat sink described in UFSAR Section 9.2.5.

The calculation update for the license renewal application incorporated the additional sounding data from the 1993 and 1998 surveillances using the same linear regression analysis method. Incorporation of the additional data resulted in a positive slope in the volume versus time curve. This volume increase was calculated to be 0.772825 acre-feet per year. Using the line developed from the analysis, the predicted 60 year EOL volume in the UHS pond would be 1461 acre-feet. The correlation between the line and the data (0.3392) indicates that the line and the data still do not correlate well.

Addition of the 2003 surveillance data leads to a smaller, but still positive slope in the curve. The volume increase with time is 0.054 acre-feet per year, with a predicted 60 year EOL UHS volume of 1421 acre-feet.

The average operating conditions for the UHS pond (inflow from the river, outflow, run-off flow, etc.) have remained consistent throughout the current operating period. SNC does not expect any changes in operating conditions or the hydrology of the river that would lead to an increase in sediment intake. In addition, the UHS pond volume surveillance would identify any unusual change.

In summary, the UHS pond surveillance data shows minor fluctuations in the pond volume (both positive and negative) occurring over time with no siltation trend indicated. The updated calculation and surveillance data demonstrate the UHS pond volume during the period of extended operation will remain above the 1325 acre-feet used in the UHS analysis.

RAI 4.5.1-1

Section 4.5.1 "Ultimate Heat Sink Silting" of the FNP LRA states that the applicant has updated the design calculations pertaining to the surveillance of the Ultimate Heat Sink (UHS) to address silting induced aging. It is further stated that this update addresses the UHS silting issue for the additional 20 years of operations in the extended term in accordance with 10 CFR 54.21(c)(1)(ii). In order to complete the review of the UHS silting issue at FNP site, the staff needs the following additional information:

c. Explain briefly the procedure that was used to determine the observed and projected rates of siltation mentioned in item b above, and summarize the significant results indicating the safety margin achieved in volume of water (acre-feet) in UHS.

Response

The observed and projected rates of siltation are based on evaluation of sounding survey data results (detailed in our response to Part (a) of this RAI). The response to Part b of this RAI describes how the method of least squares in a linear regression analysis was used to establish a trend line for the data. The method used to establish the UHS analysis value (i.e., the volume used in the evaluation described in UFSAR Section 9.2.5 to confirm the ability of the service water pond to function as an ultimate heat sink) is also described in the Part b response.

The UHS pond surveillance data shows minor fluctuations in the pond volume (both positive and negative) occurring over time with no siltation trend indicated. Pond volume projection results are summarized in the response to Part (b) of this RAI. The average measured pond volume (from the 12 sets of data taken over the last 22 years) is 1,418.5 acre-feet which results in a margin of 7% above the 1325 acre-feet value used in the UHS analysis. The minimum recorded UHS pond volume of 1403 acre-feet (from the 1983 surveillance data) which results in 5.8% margin over the UHS analysis value.

RAI B.3.5-1

NUREG/CR-5576, Survey of Boric Acid Corrosion of Carbon Steel Components in Nuclear Plants [January 1990], summarizes boric acid leakage and corrosion events that occurred in the industry prior to 1990. More recently, industry experience (refer to the operating events summarized in NRC Bulletins 2002-01 and 2003-02 and in NRC Executive Order EA-03-009) has demonstrated that the bi-metallic partial penetration welds (Alloy 82/182 welds) used in the fabrication of upper and lower RV head penetration nozzles may be susceptible to primary water stress corrosion cracking (PWSCC) that could induce leakage of the borated reactor coolant over time. However, the corresponding partial-penetration welds at FNP, Units 1 and 2, were not listed in the SNC's (Alabama Power Company's) GL 88-05 response, dated May 31, 1988, with locations that could be potential sources of borated water leaks.

The staff seeks additional clarification regarding the list of components that are within the scope of the Borated Leakage Assessment and Evaluation Program and the process the applicant uses to augment the list of components that were originally specified within the scope of the applicant's GL 88-05 response, dated May 31, 1988.

a. Provide the list of component locations that are currently within the scope of the Borated Water Leakage Assessment and Evaluation Program, and discuss the process that is used to augment of ASME Code Class 1 and 2 components locations within the scope of the aging management program (AMP) based on industry experience that is relevant to the scope and implementation of the AMP.

Response

The May 31, 1988 response to GL 88-05 for the Farley Nuclear Plant (FNP) did not restrict the program to a list of component locations. The response indicated that "A boric acid leak anywhere in the containment could cause degradation of the Reactor Coolant System pressure boundary if the leakage was allowed to accumulate on carbon steel components." The response went on to identify specific types of areas, in general, subject to leakage. The Borated Water Leakage Assessment and Evaluation Program (BWLAEP) is a living program and is updated to reflect applicable input from NRC communications including executive orders, input from industry and site-specific operating experience, and input from participation in industry initiatives (e.g., SNC's involvement in Westinghouse Owners Group and the EPRI Materials Reliability Project). SNC has processes in place that assure commitments made in formal responses to NRC communications are incorporated. SNC also has a formal process for review of industry operating experience (NRC information notices, INPO SOERs, etc.) to determine applicability to FNP activities. Recommendations and guidance from participation in industry initiatives are evaluated and incorporated as appropriate.

All borated systems at FNP are inspected for leakage and evidence of leakage through the BWLAEP. This program is formalized through the FNP Inservice Inspection (ISI) Program, the Reactor Pressure Vessel (RPV) Head Inspection activities, and various other procedures including a procedure for performing a containment general inspection to identify leaks or boric acid accumulations, a procedure for performing ASME Section XI leak inspections of the reactor coolant system, procedures for performing leakage assessment on emergency core cooling systems (ECCS), procedures for performing routine walkdowns, and guidance procedures for performing visual inspections and

corrosion assessments.

Component locations evaluated for special inspection requirements include:

- Reactor vessel top head (including penetrations);
- Reactor vessel bottom head mounted instrument penetrations;
- Alloy 600 base material and Alloy 82/182 weld locations;
- Mechanical connections within the reactor coolant pressure boundary (flanged connections, conoseals, valve body-to-bonnet connections and valve packing, pump seal housings, etc.).

RAI B.3.5-1

NUREG/CR-5576, Survey of Boric Acid Corrosion of Carbon Steel Components in Nuclear Plants [January 1990], summarizes boric acid leakage and corrosion events that occurred in the industry prior to 1990. More recently, industry experience (refer to the operating events summarized in NRC Bulletins 2002-01 and 2003-02 and in NRC Executive Order EA-03-009) has demonstrated that the bi-metallic partial penetration welds (Alloy 82/182 welds) used in the fabrication of upper and lower RV head penetration nozzles may be susceptible to primary water stress corrosion cracking (PWSCC) that could induce leakage of the borated reactor coolant over time. However, the corresponding partial-penetration welds at FNP, Units 1 and 2, were not listed in the SNC's (Alabama Power Company's) GL 88-05 response, dated May 31, 1988, with locations that could be potential sources of borated water leaks.

The staff seeks additional clarification regarding the list of components that are within the scope of the Borated Leakage Assessment and Evaluation Program and the process the applicant uses to augment the list of components that were originally specified within the scope of the applicant's GL 88-05 response, dated May 31, 1988.

b. Discuss how SNC's responses to the following NRC documents have been used to update the list of component locations and types of visual inspections credited within the scope of the Borated Water Leakage Assessment and Evaluation Program or within the scope of other aging management programs (AMPs) that provide for implementation of similar or more conservative types of inspections: NRC Bulletin 2002-01, dated March 29, 2002, and May 16, 2002; NRC's RAIs on the bulletin, dated January 17, 2003; NRC Bulletin 2003-02, dated September 19, 2003; and NRC Order EA-03-009, dated March 3, 2003, April 11, 2003, and April 18, 2003. If the responses have been used to supplement the scope of the Borated Water Leakage Assessment and Evaluation Program or other AMPs, identify which component locations have been added to the scope of the program and clarify what type of visual examinations (i.e., specify whether VT-1, VT-2 or VT-3, and whether the visual examinations are enhanced, bare-surface, qualified, etc.) will be performed on the components within the current scope of the program.

Response

SNC's responses to the referenced NRC documents (bulletins and executive order) did not change component locations inspected under the Borated Water Leakage Assessment and Evaluation Program (BWLAEP) but did result in changes in inspection activities and leakage detection methods.

The FNP responses to NRC Bulletins 2002-01 and 2002-02 provided summary information on the reactor pressure vessel (RPV) head inspections and maintenance activities at Plant Farley and information on the inspections performed at Alloy 600 and dissimilar metal Alloy 82/182 weld locations in the reactor coolant pressure boundary (RCPB). The FNP response to NRC Bulletin 2003-02 described inspection procedures, inspection results, and future plans for the inspection of RPV lower head penetrations and other Alloy 600 and Alloy 82/182 weld locations. These responses contained new, specific commitments (discussed in the following paragraphs) relative to RPV upper (top) and lower head examinations and reactor coolant pressure boundary leakage detection that are incorporated into the BWLAEP.

FNP committed to perform a semi-annual sample and analysis of the containment atmosphere for iron concentration as a measure to assist in the detection of low levels of RCS leakage. FNP also committed to perform a best effort visual examination of the metal surface under the insulation of the RPV bottom head during the next refueling outage at each unit (U1R18 during Spring 2003 and U2R16 during Spring 2004). As stated in our response to NRC Bulletin 2003-02, the RPV bottom head inspections are a direct visual aided by remote devices and meet the intent of the MRP recommendations described in MRP 2003-017. The qualification standards for the visual examination procedures require resolution of the 0.105 inch lower-case character height which was taken from the EPRI Head Penetration report as applicable for lower head penetrations and has been the standard since the 1992 Edition of ASME for VT-3 examinations. The schedule and extent of subsequent inspections of the RPV bottom head will be determined pending results of the visual examinations of the outer surface of the bottom head, the results of the root cause analysis of the bottom-mounted instrumentation at South Texas Project Unit 1, and future industry experience.

For the RPV top heads, FNP had committed to implementing the Electric Power Research Institute (EPRI) Materials Reliability Program (MRP) Inspection Plan on the existing RPV heads in addition to the existing ASME Section XI inspection requirements. Subsequently, the NRC has issued mandatory RPV head inspection requirements (Revised NRC Order EA-03-009) that now govern RPV top head inspections.

Revised NRC Order EA-03-009 has established requirements for reactor pressure vessel (RPV) head penetration inspections that assign a susceptibility category to each RPV head related to PWSCC degradation. FNP has committed to replace the RPV upper heads prior to the period of extended operation (U1 is scheduled for Fall 2004 and U2 in Fall 2005), utilizing thermally-treated Alloy 690 based metal and Alloy 52/152 weld base metal for all closure head penetrations. Although the original FNP upper RPV heads fall into the "high" susceptibility category, the replacement RPV upper heads will fall into the "replaced" susceptibility category. Therefore, inspection requirements for the upper RPV heads will be reduced prior to FNP entering into the period of extended operation based on Revised NRC Order EA-03-009. Based on Paragraph IV.C(4) of the Revised NRC Order February 20, 2004 for the "replaced" RPV head category, no RPV head or head penetration nozzle inspections would be required during the refueling outage for which the RPV head was replaced. After that time, until the effective degradation year (EDY) value reaches eight, the reduced inspection requirements consist of the following:

(i) A bare metal visual examination of 100% of the RPV head surface, including 360 degrees around each RPV head penetration nozzle every third refueling outage or five years whichever comes first, and

(ii) A nonvisual NDE (ultrasonic, eddy current or dye penetrant tests) for each penetration every fourth refueling outage or seven years whichever comes first.

Currently, FNP is considered a "high" susceptibility plant that requires performance of the above inspections every refueling outage.

RAI B.3.5-2

The applicant's FSAR Supplement summary description for the Borated Water Leakage Assessment and Evaluation Program provides a general reference to commitments made in the applicant's response to Generic Letter (GL) 88-05. However, the staff requests that the applicant amend the FSAR Supplement summary description to provide a more specific reference to the applicant's response (i.e., Alabama Power Company's response) to GL 88-05, dated May 31, 1988, and to any additional responses to NRC generic communications (i.e., Generic Letters, Bulletins, Orders, or Circular Letters) that are germane to the scope or other program attributes for the AMP or have been used to amend the program attributes for the AMP, including those responses to NRC Bulletins 2002-01 and 2003-02, and to NRC Order EA-03-009, as appropriate.

Response

Providing specific references to FNP responses to NRC generic communications that are germane to the Borated Water Leakage Assessment and Evaluation Program (BWLAEP) would be unwieldy and inconsistent with the level-of-detail presented in the FSAR, and is unnecessary. The FNP-specific responses to NRC communications are readily retrievable in the NRC Public Document Room. References to applicable NRC generic communications are incorporated into the program governing documents as appropriate.

To address the NRC's concern, SNC will revise the FSAR Supplement description in Appendix A.2.5, Borated Water Leakage Assessment and Evaluation Program as follows (changes indicated by ***bold italics***):

> The Borated Water Leakage Assessment and Evaluation program implements the plant-specific commitments made in response to NRC Generic Letter 88-05 ***and subsequent NRC communications on boric acid corrosion and leakage detection which include NRC Bulletins 2001-01, 2002-01, 2002-02, 2003-02, and NRC Order EA-03-009 (as revised).*** The program is applicable to areas where there are carbon steel and low-alloy steel structures or components, or electrical components, on which borated reactor water might leak.
>
> This program is consistent with the 10 attributes of the aging management program described in NUREG-1801, Section XI.M10.

RAI B.5.2-1

In SNC's response to Bulletin 88-09, SNC indicated that it had performed inspections of 100% of the flux detector thimble tubes at Farley Unit 1 during refueling outages Nos. 7 and 8 and at Farley Unit 2 during refueling outage No. 5. SNC's bulletin response did not indicate whether the applicant would continue to perform 100% inspections of the thimble tubes during subsequent refueling outages. The staff seeks clarification whether the scope of the Flux Detector Thimble Inspection Program will continue to perform eddy current testing (ECT) inspections of 100% of the flux detector thimble tubes. If the percentage of the flux detector thimble tubes inspected during subsequent ECT examinations will be less than 100%, the staff requests that SNC provide its technical basis for reducing the percentage of tubes inspected during implementation of the program.

Response

All accessible flux thimble tubes are inspected using ECT at each scheduled inspection. Flux thimble tubes which have been previously capped, or which are obstructed, cannot be inspected. The flux thimble tubes are inspected over their full length from the seal table to the nose of the tube at the top of the core. SNC will continue to inspect all accessible flux thimble tubes at each scheduled inspection. See the response to RAI B.5.2-3 to address scheduling of these inspections.

RAI B.5.2-3

In SNC's response to NRC Bulletin No. 88-09, dated November 2, 1988, SNC stated that the program included ECT at each refueling outage until adequate confidence is established in wear rate projections. In an audit trip report issued on January 12, 1990, the staff stated that SNC's inspection frequency of every refueling outage is acceptable. However, during the audit of November 3-7, 2003, the staff determined that the applicant is basing its implementation of Flux Detector Thimble Inspection Program on the analysis in Westinghouse Proprietary Class 2 Topical Report WCAP-12866, "Bottom Mounted Instrument Flux Thimble Wear" dated January 11, 1991. The staff seeks confirmation that the analysis in WCAP-12866 has not changed SNC's inspection frequency for the Flux Detector Thimble Inspection Program from that approved in the audit trip report of January 12, 1990. If analysis described WCAP-12866 has revised the inspection frequency for the Flux Detector Thimble Inspection Program from a frequency of once every refueling outage, state what the new inspection frequency is and provide the technical basis (i.e., using wear rate projections to support a less frequent basis) for supporting the conclusion that the new inspection frequency will be capable of monitoring for the integrity of the thimble tubes prior to a loss of thimble tube function.

Response

In the November 2, 1988 response to NRC Bulletin 88-09 for FNP, Alabama Power Company stated "Alabama Power Company will continue to monitor thimble tube wear by periodic testing and will participate in Westinghouse Owner's Group (WOG) activities to establish recommended testing options, acceptance criteria, and recommended corrective actions. *When issued, the WOG recommended actions will be reviewed and the Alabama Power Company program modified, as appropriate.* In the interim period prior to issuance of the WOG recommendations, Alabama Power Company will continue with its current program which is consistent with the requirements of NRC Bulletin 88-09" (emphasis added).

In its January 12, 1990 audit trip report, the NRC noted that "The Licensee stated that eddy current inspections will be performed during every refueling outage *until there is sufficient data to justify longer inspection intervals"* (emphasis added). In addition, the NRC concluded: "The Licensee has considered long term corrective actions and is prepared to replace tubes if necessary. Although no long term commitments have been made, we understand that the Licensee will continue participating in industry programs (such as WOG) and follow new developments related to this issue."

The FNP Flux Detector Thimble Inspection Program has been maintained in accordance with the November 2, 1988 response to NRC Bulletin 88-09, including the potential for modifications to the inspection interval. This potential for modifications to the inspection interval was acknowledged by the NRC in its January 12, 1990 audit trip report.

The inspection schedule implemented by the FNP Flux Detector Thimble Inspection Program is in conformance with the current recommendations of WCAP-12866, "Bottom Mounted Instrument Flux Thimble Wear" dated January 11, 1991. The inspection schedule is not a pre-established, fixed frequency. The inspection schedule is variable, based on projections of thimble tube wear calculated from measurements of current wear. Early in the inspection program, inspections were performed every outage to establish wear rate patterns characteristic of each unit. Once a history had been

established, the WCAP-12866 wear rate projection methodology became the basis for determining the acceptable interval between inspections. After each inspection the recommended date of the next inspection is determined. Operating experience at FNP and across the industry indicates that the wear rate prediction methodology is a conservative way to project wear of the flux thimble tubes.

In 1993 the schedule of inspections at FNP was changed from every outage to every other outage, unless wear predictions dictated that an inspection be scheduled at an earlier date. This change was based on Westinghouse's recommendation.

The FNP Unit 2 flux thimble tubes are currently inspected every other outage in accordance with WCAP-12866 guidance. The last inspection was performed during the Fall 2002 refueling outage (2R15). The next inspection is scheduled for the Fall 2005 refueling outage (2R17). Planning activities are in progress to replace the Unit 2 flux thimble tubes. After the flux thimble tubes are replaced the inspection schedule will be revised in accordance with the latest guidance based on WCAP-12866, and industry and FNP operating experience.

The FNP Unit 1 flux thimble tubes were replaced with wear resistant, chrome plated thimble tubes during the Fall 1998 refueling outage (1R15). In 2003 the inspection schedule was extended to every third refueling outage based on Westinghouse's recommendation. The last inspection was performed during the Fall 2001 refueling outage (1R17). The next inspection is scheduled for the Spring 2006 refueling outage (1R20).

The current inspection schedules for FNP Units 1 and 2 are established based on predictions of flux thimble tube wear. These predictions are calculated in accordance with the methodology described in WCAP-12866. The unit-specific wear history is used as input to the wear calculation. Both industry and FNP specific operating experience is considered when the date for the next inspection is established. This experience confirms that the WCAP-12866 methodology is a conservative way to manage wear of flux thimble tubes.

RAI B.5.2-4

The NRC previously approved the Flux Detector Thimble Inspection Program in an NRC Audit Trip Report dated January 12, 1990. In the audit trip report, the staff determined that the applicant was basing its evaluations of wear on an acceptance criterion of 65% through-wall wear in the thimble tubes. However, during the staff's audit of November 3-7, 2003, the staff verified that SNC is currently using Westinghouse Proprietary Class 2 Topical Report WCAP-12866, "Bottom Mounted Instrument Flux Thimble Wear [January 11, 1991] as its current design basis document for evaluating wear the may be detected in the Farley flux thimble tubes as a result of SNC's implementation of the Flux Detector Thimble Inspection Program. This WCAP uses an acceptance criteria of 80% through-wall wear-induced degradation as its basis for performing the evaluations of wear in the Farley flux detector thimble tubes. The staff requests that SNC provide further technical justification and a technical basis for changing the acceptance criterion for the Flux Detector Thimble Inspection Program from 65% through-wall wear and for concluding that 80% through-wall wear is considered to be acceptable for maintaining the component intended functions of the flux detector thimble tubes. The applicant is requested to include in the technical justification, as appropriate, an assessment of whether or not the establishment of an 80% through-wall acceptance criterion is in conformance with the minimum acceptable wall thickness criterion for the thimble tubes (including allowances to take into account wear that is projected to occur in the thimble tubes during the interval that occurs between examinations and NDE uncertainties).

Response

FNP is committed to monitor thimble tube wear by periodic testing and to participate in Westinghouse Owner's Group (WOG) activities to establish recommended testing options, acceptance criteria, and recommended corrective actions. The 65% through-wall acceptance criterion was the preliminary acceptance criterion established based on Westinghouse analysis and acknowledged by the NRC in its January 12, 1990 audit trip report. The NRC acknowledged that "The Licensee is participating in the Westinghouse Owner's Group (WOG) Program on thimble tube wear. This program will develop more accurate wear scar standards and refine the acceptance criteria for wear based on testing of tube samples from operating plants."

In January 1991, Westinghouse issued WCAP-12866, "Bottom Mounted Instrumentation Flux Thimble Wear." This WCAP established a refined acceptance criterion of 80% through-wall wear. The refined acceptance criterion included results from testing of tube samples. WCAP-12866 concludes that flux thimbles have a high residual strength even when subject to wall loss on the order of 90%, and that the thimbles will maintain their functional and structural integrity with up to 85% wall loss for all operating modes. The WCAP recommends an acceptance criterion of 80% through-wall wear be used for conservatism. Uncertainties inherent in the eddy current examination process were considered in the development of the acceptance criteria.

The Staff question also requests an assessment of whether the acceptance criterion includes an allowance to take into account wear that is projected to occur in the interval between examinations. Since the 80% acceptance criterion is applied to the wear which is projected to exist at the next inspection, wear in the interval between inspections is accounted for. Appropriate corrective action will be taken for flux thimble tubes which are projected to exceed the acceptance criteria before the next inspection.

The 80% through-wall acceptance criterion developed by Westinghouse in WCAP-12866 has previously been accepted by the Staff in the SER for Catawba/McGuire License Renewal, Section 3.1.3.2.2.

RAI B.5.2-5

In Section B.5.2 of the LRA, SNC indicated that the original flux detector thimble tubes at Farley Unit 1 were replaced during Unit 1 refueling outage No. 15 with thimble tubes fabricated from chrome-coated, strain-hardened stainless steel. Clarify whether the wear experience for the thimbles tubes at Farley Unit 1 or the change in the material of fabrication for the flux detector thimble tubes at Farley Unit 1 have been used as a basis for revising the [Scope of Program], the [Monitoring and Trending], and the [Acceptance Criteria] program attributes for the Flux Detector Thimble Inspection Program, as implemented for the Farley Unit 1. If the wear experience or the change in the material of fabrication for the flux detector thimble tubes at Farley Unit 1 have been used to revise the [Scope of Program], [Monitoring and Trending], and [Acceptance Criteria] program attributes, as implemented for Farley Unit 1, clarify further and discuss the responses to D-RAIs B.5.2-1, B.5.2-2, and B.5.2-3 whether and how the [Scope of Program], [Monitoring and Trending], and [Acceptance Criteria] program attributes for the Flux Detector Thimble Inspection program differ from Unit 1 to Unit 2, if at all.

Response

The Program Scope (B.5.2.3), Monitoring and Trending (B.5.2.7), and Acceptance Criteria (B.5.2.8) have not been revised due to the wear experience or the change in the material of fabrication for the flux detector thimble tubes at Farley Unit 1. All flux thimble tubes on both Units are in the scope of the program. Wall thickness measurements will be conducted to detect loss of material from the flux detector thimble tubes at both Units. Examination results will be trended and wear rates will be calculated in accordance with WCAP-12866 for both Units. Examination frequency will be based on wear predictions. Results of the wall thickness measurements will be evaluated using a wear rate formula which is described in WCAP-12866. The wear rate formula will be used to determine the earliest projected date that a flux detector thimble tube can be anticipated to exceed the wall thickness limit. This determination is performed in accordance with WCAP-12866 for both units. The program attributes of the Flux Detector Thimble Inspection Program are therefore the same for both Units.

ENCLOSURE 2

Joseph M. Farley Nuclear Plant Units 1 and 2

Application for License Renewal

Supplemental Responses to Previous Requests for Additional Information

RAI 4.3.4-1 – Supplemental Response

In RAI 4.3.4-1, the staff requested additional information on FNP's containment tendon analysis in order for the staff to make a reasonable assurance conclusion that the applicant demonstrates the adequacy of the analysis projected for the extended period of operation. SNC provided the requested information in RAI response letter NL-04-0318 dated March 5, 2004. In the response, the data for the tendons was provided on a "per wire" basis. In a March 15, 2004 telephone conference, the staff asked the applicant to present the prestressing forces on a per tendon basis.

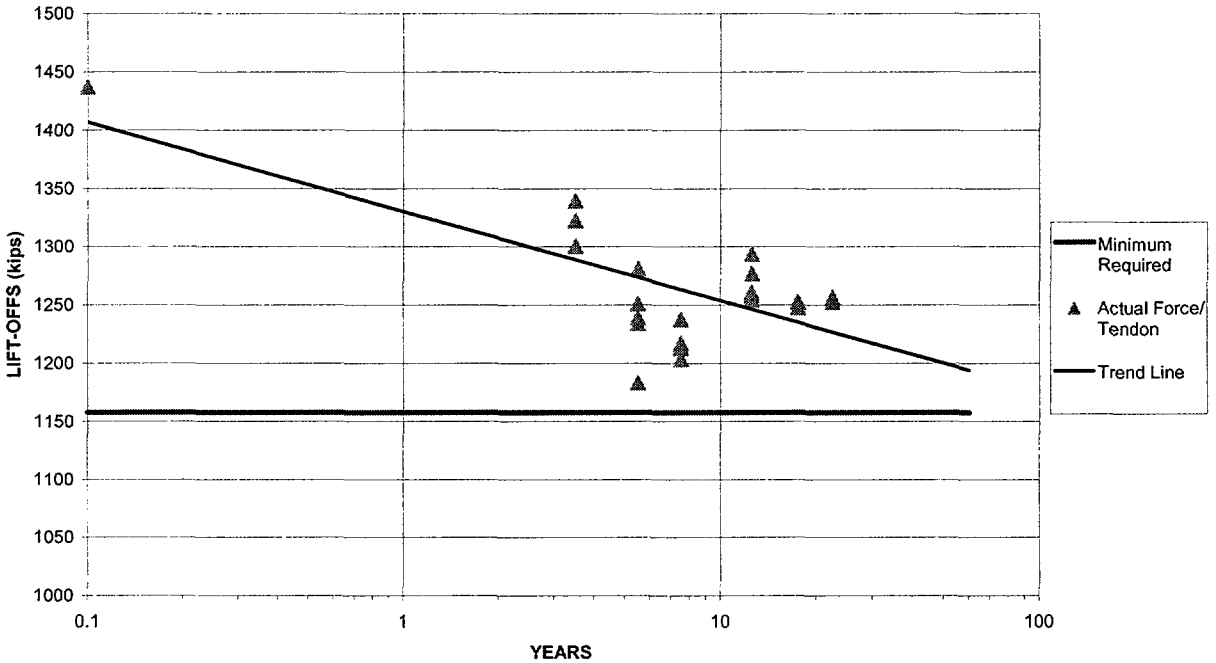
(a) The following are the minimum required prestressing forces per tendon (170 wires/tendon):

Hoop Tendon = 1021.7 kips/Tendon
Dome Tendon = 1079.5 kips/Tendon
Vertical Tendon = 1157.7 kips/Tendon

(b) For each group of tendons, trend lines of the projected prestressing forces based on the regression analysis of the measured prestressing forces are included with the plots for item c below.

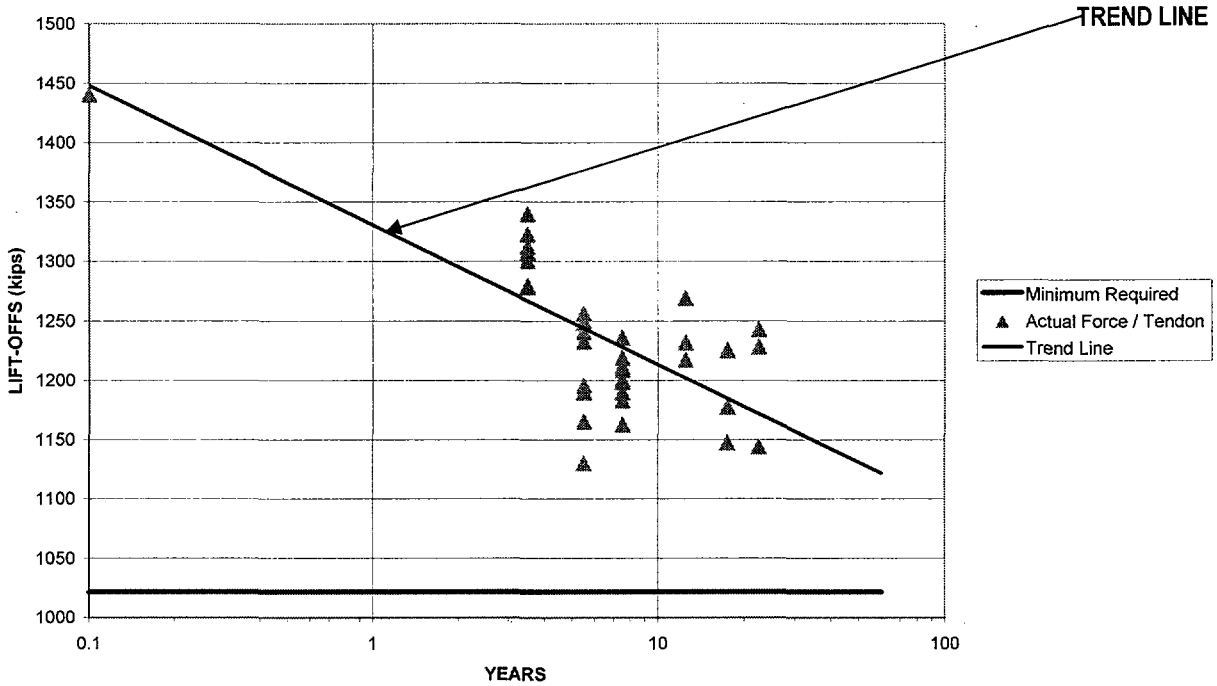
(c) Comparison of prestressing forces projected to the end of the extended period of operation with the minimum required prestress are plotted for each group of tendons on a per tendon basis on the subsequent pages.

UNIT 1 VERTICAL TENDONS
ACTUAL FORCE TREND PER TENDON BASIS
(from past 6 surveillances)



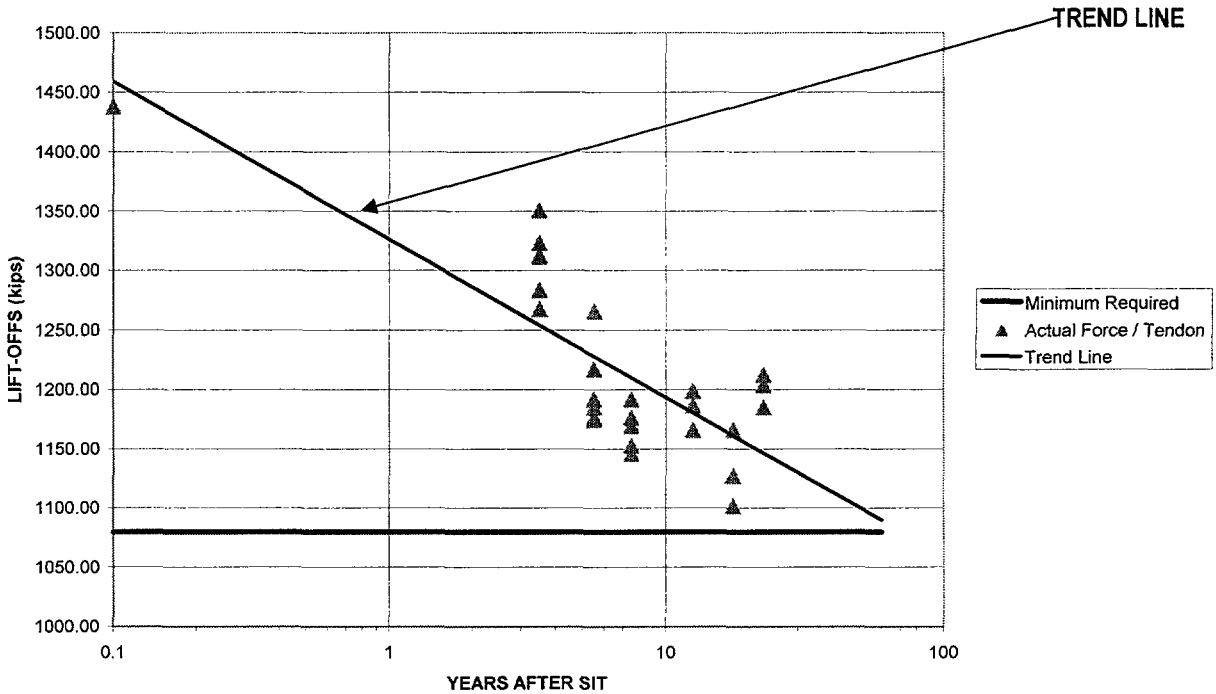
Year	Tendon	No of Wires	Actual Force (kips)	Year	Tendon	No of Wires	Actual Force (kips)
0.1	All	Avg. 169.94	1437.2	7.5	V-100	169	1213.4
3.5	V-16	170	1339.6	7.5	V-128	170	1237.6
3.5	V-39	170	1300.5	12.5	V-14	170	1254.6
3.5	V-66	170	1322.6	12.5	V-31	169	1260.7
3.5	V-95	170	1300.5	12.5	V-72	170	1293.7
3.5	V-116	170	1322.6	12.5	V-109	170	1276.7
5.5	V-16	170	1251.2	12.5	V-120	170	1258.0
5.5	V-27	169	1281.0	17.5	V-61	170	1247.8
5.5	V-86	170	1234.2	17.5	V-99	170	1247.8
5.5	V-105	170	1239.3	17.5	V-113	170	1252.9
5.5	V-126	170	1183.2	22.5	V-1	170	1256.3
7.5	V-5	170	1217.2	22.5	V-43	170	1252.9
7.5	V-18	170	1213.8	22.5	V-80	170	1252.9
7.5	V-60	170	1203.6				

UNIT 1 HOOP TENDONS
ACTUAL FORCE TREND PER TENDON BASIS
(from past 6 surveillances)



Year	Tendon	No of Wires	Actual Force (kips)	Year	Tendon	No of Wires	Actual Force (kips)
0.1	All	Avg. 169.14	1440.1	7.5	H8AB	166	1208.5
3.5	H1BA	170	1322.6	7.5	H14AB	170	1190.0
3.5	H6BA	166	1306.4	7.5	H18CA	170	1183.2
3.5	H12BA	163	1279.5	7.5	H20CA	170	1162.8
3.5	H17BA	170	1278.4	7.5	H25BC	170	1218.9
3.5	H24BA	170	1339.6	7.5	H33BC	170	1212.1
3.5	H25CA	168	1307.0	7.5	H36AB	170	1210.4
3.5	H29BC	170	1312.4	7.5	H38CA	170	1200.2
3.5	H32BA	170	1307.3	7.5	HH40BC	170	1198.5
3.5	H36CA	170	1312.4	7.5	H44CA	170	1235.9
3.5	H39BC	170	1300.5	12.5	H2AB	166	1231.7
5.5	H6AB	166	1248.3	12.5	H26AC	170	1217.2
5.5	H12AB	162	1195.6	12.5	H44BC	169	1269.2
5.5	H25CA	167	1190.7	17.5	H18CB	170	1147.5
5.5	H26AB	166	1165.3	17.5	H27CA	169	1177.9
5.5	H29AB	170	1190.0	17.5	H42BA	169	1225.2
5.5	H30CA	169	1240.5	22.5	H3BA	168	1228.1
5.5	H36CA	170	1256.3	22.5	H26CB	170	1144.1
5.5	H36BC	170	1232.5	22.5	H42CA	170	1242.7
5.5	H39AB	164	1130.0				
5.5	H39BC	170	1249.5				

UNIT 1 DOME TENDONS
ACTUAL FORCE TREND PER TENDON BASIS
(from past 6 surveillances)



Year	Tendon	No of Wires	Actual Force (kips)	Year	Tendon	No of Wires	Actual Force (kips)
0.1	All	Avg. 169.91	1437.9	7.5	D110	170	1152.6
3.5	D114	169	1267.5	7.5	D119	170	1191.7
3.5	D123	170	1283.5	7.5	D203	170	1145.8
3.5	D202	170	1312.4	7.5	D229	170	1169.6
3.5	D230	169	1311.4	7.5	D303	170	1176.4
3.5	D309	169	1323.3	7.5	D319	170	1191.7
3.5	D317	168	1350.7	12.5	D121	170	1198.5
5.5	D107	169	1216.8	12.5	D228	169	1186.4
5.5	D122	170	1176.4	12.5	D320	170	1166.2
5.5	D227	170	1174.7	17.5	D110	170	1166.2
5.5	D231	170	1191.7	17.5	D201	170	1101.6
5.5	D309	169	1265.8	17.5	D318	170	1127.1
5.5	D324	170	1184.9	22.5	D102	170	1212.1
				22.5	D118	170	1184.9
				22.5	D311	170	1203.6

RAI 2.1-1 – Supplemental Response (Part 1)

RAI response letter NL-04-2623 dated January 9, 2004 provided SNC's response to RAI 2.1-1. After discussions with the NRC staff concerning the response to RAI 2.1-1, parts A and C, SNC agreed to broaden the methodology used for scoping of non-attached non safety-related (NSR) piping in accordance with 10 CFR 54.4(a)(2) in the following manner:

1. Eliminate any distance criteria for excluding a spatial interaction between SR and NSR SSCs; and
2. Further evaluate spatial interaction effects on mechanical and structural SR SSCs (i.e., do not limit the valid target considerations to electrical SSCs).

The details of the methodology change are presented below:

SNC has agreed to eliminate the spray distance criterion from the process of determining which NSR SSCs are in scope for the criterion of 10 CFR 54.4(a)(2). This change in scoping methodology brings SNC in alignment with other recent applicants, most notably the V. C. Summer scoping process. The methodology change invokes the plant spaces approach which assumes a spatial interaction can potentially occur if the SSCs are located in the same space. For the purposes of this process, a space is defined by the room in which the SR and NSR components are located.

SNC will consider all fluid-bearing NSR SSCs to be in the scope of the criterion of 10 CFR 54.4(a)(2), provided the NSR components are located in the same space as the SR SSCs. In addition, if the SR SSC is determined to not be vulnerable to the effects of the spray/leakage, then the NSR SSC would not be in the scope of the Rule since the NSR SSC could not prevent or adversely affect the SR SSC from performing its safety related function. The revised methodology will include evaluating the impact of sprays and leaks on mechanical and structural SR SSCs, as well as electrical SR SSCs, with no limitations on the duration of the sprays/leaks.

SNC is in the process of evaluating the impact of these changes to the scoping methodology upon the scoping, screening, and aging management review results and will respond with those changes in a subsequent supplemental response.