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SOUTHERN COMPANY
Energy to Serve Your World℠

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NL-04-0473

U. S. Nuclear Regulatory Commission
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Joseph M. Farley Nuclear Plant Units 1 and 2
Application for License Renewal –
Requests for Additional Information (RAIs)

Ladies and Gentlemen:

This letter is in response to several requests in the review of the license renewal application for Joseph M. Farley Nuclear Plant, Units 1 and 2. First, this letter is in response to your letter dated March 8, 2004 requesting additional information for the review of the Joseph M. Farley Nuclear Plant, Units 1 and 2, License Renewal Application. These responses are provided in Enclosure 1.

Second, at the request of the NRC, SNC is providing an early response to certain RAIs in your request of March 23, 2004. This is provided in Enclosure 2.

Finally, in a teleconference on March 30, 2004, the NRC requested that SNC clarify the response to RAI 3.4-1 and RAI 3.4-5 previously submitted in letter NL-04-0318 dated March 5, 2004. These responses are provided in Enclosure 3 and replace the original responses in the March 5th letter.

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.

A099

Respectfully submitted,

SOUTHERN NUCLEAR OPERATING COMPANY

L. M. Stinson
Vice President, Farley

Sworn to and subscribed before me this 7th *day of* April*, 2004.*

Gloria H. Buie
Notary Public

My commission expires: 6-7-05

LMS/GMC/slb

Enclosures:
1. Responses to March 2, 2004 Requests for Additional Information, Joseph M. Farley Nuclear Plant, Units 1 and 2
2. Responses to March 23, 2004 Requests for Additional Information, Joseph M. Farley Nuclear Plant, Units 1 and 2 (Partial)
3. Revised Responses to RAI 3.4-1 and RAI 3.4-5, Joseph M. Farley Nuclear Plant Units 1 and 2

cc: Southern Nuclear Operating Company
Mr. J. B. Beasley Jr., Executive Vice President
Mr. D. E. Grissette, General Manager – Plant Farley
Document Services RTYPE: CFA04.054; LC# 13993

U. S. Nuclear Regulatory Commission
Ms. T. Y. Liu, License Renewal Project Manager
Mr. L. A. Reyes, Regional Administrator
Mr. S. E. Peters, NRR Project Manager – Farley
Mr. C. A. Patterson, Senior Resident Inspector – Farley

Alabama Department of Public Health
Dr. D. E. Williamson, State Health Officer

ENCLOSURE 1

Joseph M. Farley Nuclear Plant Units 1 and 2

Application for License Renewal

Responses to March 8, 2004 Requests for Additional Information

RAI 3.3-6

In several systems (including the control room area ventilation system, the auxiliary and radwaste area ventilation system, and the liquid waste and drains system), the applicant credited the One-Time Inspection Program for managing the aging effects of loss of materials, change in material property, and cracking for elastomers components. However, the One-Time Inspection Program is intended for use as a verification AMP to check the degree of aging of components when significant aging is not expected, while periodic inspections are more appropriate if aging effects can reasonably be expected to occur. The degradation of elastomers depends upon the service loads and environmental conditions, including temperature, radiation level, and presence of aggressive chemicals. The applicant is requested to provide additional information on the service loads and environment of the components to justify the use of One-Time Inspection Program for managing the aging effects of elastomers.

Response:

Background on Environmental Considerations for Elastomers

EPRI Technical Report TR-1002950, "Aging Effects for Structures and Structural Components (Structural Tools), Revision 1", indicates that elastomers are potentially subject to thermal degradation. Thermal degradation results in changes in the elastomer properties and potentially cracking. The EPRI Structural Tools reports continuous temperature ratings for the evaluated elastomers ranging from 130 °F for natural rubber to 275 °F for silicone rubber. The EPRI Structural Tools states that in general, if the ambient temperature is less than 95 °F, then thermal aging is not significant for the period of extended operation. This is a conservative threshold temperature intended to encompass all elastomer materials. When the specific elastomer material type is considered, installation in thermal environments marginally above 95 °F may also not be susceptible to significant thermal degradation.

The EPRI Structural Tools indicates that degradation of natural rubbers can occur through simultaneous exposure to ultraviolet radiation and oxygen, which supports an ozone – rubber reaction that embrittles the rubber and can result in cracking or checking. Sources of ultraviolet radiation include both sunlight and ultraviolet or fluorescent lamps. Areas exposed to direct sunlight are expected to have the highest potential for degradation due to ultraviolet radiation / ozone exposure since this environment best supports both the formation of ozone and the reaction between ozone and natural rubbers. The EPRI Structural Tools indicates that nitrile rubber, butyl rubber, silicone rubber, and neoprene either have good resistance to ultraviolet / ozone degradation or are essentially unaffected by ultraviolet radiation / ozone.

The EPRI Structural Tools indicates that ionizing radiation can significantly alter the molecular structure and material properties of elastomers. Radiation levels exceeding 10^6 Rads is the lowest reported threshold for irradiation effects in an elastomer of the types in scope for license renewal. Conservatively, radiation embrittlement is postulated for elastomers in locations above this threshold.

Attack by chemical species is also a potential degradation mechanism. Experience has shown that rubbers can be embrittled by exposure to certain chemicals present in nuclear power plants. Table 28-27 of Perry's Chemical Engineer's Handbook notes that most all natural and synthetic rubbers offer poor resistance to oils and fuel products. Resistance to water and acids is noted to be fair to good for some rubbers and excellent for others, with resistance to acid attack generally the limiting factor.

Discussion of FNP Environments for Elastomers in Scope of One-Time Inspection Program:

Control Room Area Ventilation System: Elastomer components in the Control Room Area Ventilation System are located inside the Non-Rad portion of the Auxiliary Building. These components are protected from environmental effects, have no radiation loading, are not subject to attack by aggressive chemicals, and operate at temperatures below which thermal degradation is a significant concern.

Auxiliary & Radwaste Area Ventilation System: The in-scope elastomer components in the Auxiliary & Radwaste Area Ventilation System are divided between two locations (Rad-portion and non-Rad portion of the Auxiliary Building). Flexible connectors for the battery room exhaust fans are located inside the Non-Rad portion of the Auxiliary Building. These components are protected from environmental effects, have no radiation loading, are not subject to attack by aggressive chemicals, and operate at temperatures below which thermal degradation is a significant concern. Flexible connectors for the penetration room filtration fans are located inside the Rad portion of the Auxiliary Building. These components are protected from environmental effects, are not subject to attack by aggressive chemicals, and operate at temperatures below which thermal degradation is a significant concern. While these components are located in the Rad portion of the Auxiliary Building, normal operating conditions provide for no significant radiation loading.

Primary Containment Ventilation System: The in-scope elastomer components in the Primary Containment Ventilation System are divided between two locations. Flexible connectors for the containment purge fans are located inside the Rad portion of the Auxiliary Building. These components are protected from environmental effects, are not subject to attack by aggressive chemicals, and operate at temperatures below which thermal degradation is a significant concern. While these components are located in the Rad portion of the Auxiliary Building, normal operating conditions provide for no significant radiation loading. Flexible connectors for the containment coolers are located inside the Containment Building. These components are replaced periodically as a preventive maintenance task. These components are therefore short-lived and not subject to an aging management review.

Liquid Waste & Drains System: The Elastomer components in the Liquid Waste & Drains System are expandable plugs used to plug the penetration room floor drains. Plugging of the floor drains is necessary to provide a pressure boundary for the Penetration Room Filtration System. These floor drain plugs are located inside the Rad portion of the Auxiliary Building. These components are protected from environmental effects and operate at temperatures below which thermal degradation is a significant concern. While these components are located in the Rad portion of the Auxiliary Building, normal operating conditions provide for no significant radiation loading. The floor drain plugs are installed in drains which would collect leakage, spills, etc. Although unlikely, exposure to aggressive chemicals is considered. The One-Time Inspection Program will confirm the plugs have not been exposed to conditions detrimental to the seals.

Conclusion:

SNC considers the One-Time Inspection Program an appropriate aging management program for these elastomer components. These elastomer components are installed in locations which provide minimal exposure to potential aging mechanisms therefore significant aging is not expected.

RAI 3.3-7

Galvanized steel components exposed to a moist air environment may experience corrosion. However, for numerous systems, the LRA states that there is no aging effect on galvanized steel ducts and fittings exposed to an inside environment, which is moist and humid air. This conclusion may not be supported by industry experience. The applicant is requested to provide the technical basis for this conclusion considering industry experience.

Response:

Operating experience indicates significant condensation is necessary to have an aging effect requiring management (AERM) on galvanized steel. For corrosion of galvanized steel components to occur, oxygen plus moisture collection on the component surface is required. Galvanized carbon steel ducts and fittings in an inside environment listed in the LRA with no aging effect requiring management do not experience significant condensation/moisture collection, because they operate at temperatures similar to the surrounding ambient air conditions and significant condensation is not expected.

Significant moisture collection/condensation can occur on galvanized steel ducts and fittings where humid air is exposed to a much colder surface, such as at cooling coils. Therefore, SNC listed cooling coil units (including their housings) in the LRA with aging effects associated with moisture collection/ condensation. In locations where significant moisture collection/condensation can occur, the aging effects requiring management for galvanized carbon steel were the same as for plain carbon steel and therefore SNC elected to include them in the LRA under a single material type "Carbon Steel". Examples in the LRA include:

- "Cooling Coil Units and Associated Refrigerant Piping (housings, coils, fins, drains, refrigerant lines)" in LRA Table 3.3.2-9;
- "Cooling Units (housings and fan/coil fins only)" in Table 3.3.2-10; and
- "Equipment Frames and Housings (includes cooling coil housings and cooling fins)" in Table 3.3.2-11.

RAI 3.3-8

In several systems, for example, the auxiliary and radwaste area ventilation system, and the fire protection system, the applicant identified the loss of materials as plausible aging effect on galvanized steel components in the inside environment and credited the Borated Water Leakage Assessment and Evaluation Program (BWLAEP) for managing this aging effect. However, galvanized steel components are not in the scope of the BWLAEP, and it is not clear from the LRA what mitigation or corrective activities will be taken if such corrosion is detected. The applicant is requested to provide information on the effects of boric acid corrosion on the galvanized steel, and how to manage this aging effect. The applicant is also requested to provide operating experience, if any, on boric acid corrosion on the relevant galvanized steel components.

Response:

The reference to "carbon steel" components in LRA Section B.3.5 is inclusive of all components that are fabricated from a carbon steel base metal. For the FNP LRA, "carbon steel" includes galvanized steel components such as the galvanized steel ducts and fire protection components identified above, and alloy steels such as used in bolting.

Borated water systems at FNP are inspected for leakage and evidence of leakage by the BWLAEP. When boric acid leaks are discovered, the BWLAEP identifies the components within the boric acid leak-path in addition to the leakage source, such that the appropriate corrective action is performed. A review of plant-specific operating experience revealed no evidence of loss of material due to boric acid corrosion on galvanized steel components, including those within scope for license renewal.

The galvanized material of these components consists of carbon steel coated with a thin outer layer of zinc. The zinc tends to neutralize any acidic moisture that makes contact with the material surface.

Due to the protective nature of the zinc coating of the carbon steel surface, loss of material due to boric acid is expected to be less severe than plain carbon steel but is assumed to occur. Galvanized carbon steel materials are conservatively included within the scope of BWLAEP that have spatial locations near borated water system components.

Therefore, loss of material in the inside environment for galvanized carbon steel components will be adequately managed during the period of extended operation.

RAI 3.3-9

In Table 3.0.4-1 (p. 3.0-14) of the LRA, the applicant provided specifics of the inside environment. In particular, it provided the average temperature of 120 degree F and the humidity range of 5-95% within containment. The applicant is requested to clarify whether the conditions specified for the containment environment are expected to be bounding for inside environment for all those buildings listed in the "description" column, and whether those conditions were assumed for the aging of all components in an inside environment. Also, discuss whether conditions exist that render components susceptible to periodic wetting and drying and, if so, address the issue of applicable aging effects in these types of inside environments.

Response:

The "Inside" environmental descriptor was used in the LRA to represent the containment environment and the environments found within environmentally controlled structures. As a minimum, the minimum temperature in these structures is controlled to prevent freezing. Ventilation is also provided. Although environmental conditions inside containment are the bounding conditions for the "Inside" environment, the actual conditions experienced, including operating experience, were considered in the aging management reviews.

In evaluating the potential for condensation and water pooling, all areas with an inside environment were assumed to have high relative humidity. The potential for condensation and periodic wetting and drying is driven by the operating temperature range for the process fluid, such as occurs with relatively cold service water and in the various cooling coil units. Anti-sweat insulation is installed on the piping which is most prone to condensing atmospheric moisture. Process lines that operate at high temperatures result in localized temperatures above the ambient conditions and therefore do not have a potential for periodic wetting and drying. The potential for periodic wetting and drying was evaluated in the aging management reviews for the individual components and aging management program selection. For susceptible materials in susceptible locations, loss of material was identified as an aging effect requiring management in the Inside environment.

In evaluating elastomers (see response to RAI 3.3-6) the localized temperatures and radiation levels were considered in the aging management reviews.

RAI 3.3-10

The Water Chemistry Control Program is normally augmented by an inspection program to verify the effectiveness of the AMP, especially for stagnant or low-flow areas. For example, the applicant credited Water Chemistry Control Program augmented by One-Time Inspection Program to manage the aging effect for carbon steel components exposed to closed cycle cooling water environment. However, for several auxiliary systems, the Water Chemistry Control Program is credited for managing the loss of material for the stainless steel components exposed to borated water or treated water (including closed cooling water) without being augmented by an inspection program. The applicant is requested to provide justification for the use of the Water Chemistry Control Program without an inspection program to verify its effectiveness for managing the loss of material for stainless steel components.

Response:

NUREG-1801, section XI.M2, recommends a one-time inspection "... as identified in the GALL report ...". SNC cannot identify any NUREG-1801 recommendation for a one time inspection of stainless steel auxiliary system group components exposed to borated water or treated water environments.

NUREG-1801 recognizes that the preventive nature of the water chemistry control program is generally considered to be adequate to manage the effects of aging through the period of extended operation for stainless steel components exposed to borated water or treated water, including closed-cycle cooling water. Inspection programs are not considered to be necessary for all systems and components, based on the non-corrosive environments and the corrosion resistant nature of stainless steels. NUREG-1801 therefore does not normally require for stainless steel component types that water chemistry control be augmented by an inspection program. The FNP aging management review results are consistent with the aging management programs recommended by NUREG-1801.

Stainless steel components derive their corrosion resistance from the thin, tightly adherent, passive chromium oxide layer that forms at the component surface. If the environmental conditions are not sufficiently aggressive to penetrate this oxide layer, then no significant corrosion is expected to result. Conversely, if the environment is sufficiently aggressive to disrupt the oxide layer then, localized corrosion may occur.

For austenitic stainless steels, 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. Appendix A of the EPRI Mechanical Implementation Guideline and Mechanical Tools Rev. 3 (EPRI TR-1003056) indicates that localized corrosion of stainless steels exposed to treated water (including borated water) is not a significant concern when dissolved oxygen concentrations are less than 100 ppb and concentrations of detrimental ionic species are less than 150 ppb.

Borated Water Environment:

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) conclude 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.

SNC agrees that in the normal borated water environment, stainless steel components are not subject to significant general, pitting, and crevice corrosion. SNC conservatively identified loss of material (due to pitting and crevice corrosion) as a potential aging effect that is adequately managed by the Water Chemistry Control Program without supplemental one-time inspections.

The FNP Water Chemistry Control Program is implemented consistent with the EPRI PWR Primary Water Chemistry Guidelines (EPRI TR-105714). This chemistry control program provides for both a strongly reducing environment via the addition of oxygen scavengers and strict control of detrimental ionic species. These controls limit both dissolved oxygen and detrimental ionic species concentrations to values well below those specified by the EPRI Mechanical Tools.

FNP and industry wide operating experience confirm that pitting and crevice corrosion of austenitic stainless steels has not been an issue of concern. FNP inservice inspections performed in accordance with Section XI of the ASME Code include numerous inspection locations consisting of the borated water/stainless steel environment and material combination and include normally stagnant and low flow areas. Inservice inspections include both pipe welds and component internal surfaces. The examinations would identify crevice corrosion or pitting. These inservice inspections have been performed for many years, and do not indicate a history of, or susceptibility to, loss of material due to pitting or crevice corrosion.

Treated Water Environment (Reactor Makeup Water System, Demineralized Water System, Sampling System):

This discussion of treated water includes Steam and Power Conversion systems because portions of the steam generator blowdown system sample lines are in the scope of the Sampling System. The Sampling System is included in the auxiliary systems group.

The FNP Water Chemistry Control Program is implemented consistent with the EPRI PWR Primary Water Chemistry Guidelines (EPRI TR-105714) and EPRI Secondary Water Chemistry Guidelines (EPRI TR-102134). The chemistry control program provides for strict control of detrimental ionic species concentrations to values well below those specified by the EPRI Mechanical Tools. Sulfates and chlorides are monitored in steam generator blowdown since steam generator blowdown provides a reliable indicator of anion content throughout turbine cycle. Additionally, chloride, fluoride, and sulfate content and total conductivity are monitored at appropriate points during the production of make-up water in the Water Treatment Plant. These controls limit detrimental ionic species concentrations to values well below those specified by the

EPRI Mechanical Tools as contributing to corrosion.
Dissolved oxygen is monitored in the condensate and feedwater systems, CST, RMWST, and in the Water Treatment Plant during production of demineralized water. Dissolved oxygen is typically controlled in Steam and Power Conversion systems by use of oxygen scavengers such as hydrazine. In the CST and RMWST, dissolved oxygen is controlled by use of tank bladders. Dissolved oxygen is expected to be rapidly depleted in stagnant treated water systems. Dissolved oxygen is therefore controlled in those systems where a high oxygen concentration could contribute to accelerated corrosion.

FNP and industry wide operating experience confirm that pitting and crevice corrosion of austenitic stainless steels has not been an issue of concern. Reviews of FNP operating experience do not indicate a susceptibility to loss of material in stainless steel in a treated water environment.

Closed-Cycle Cooling Water Environment:

The FNP Water Chemistry Control Program limits chlorides and fluorides in the Component Cooling Water System to the low ppm range. These limits are consistent with the limits provided in EPRI TR-107396, "Closed-cycle Cooling Water Chemistry Guideline." Chlorides and fluorides are monitored in the emergency diesel generator (EDG) jacket water system as an indicator of inleakage. Also, pH in CCCW systems is maintained greater than neutral to reduce the potential for crevice corrosion and pitting by promoting stabilization of the passive oxide layer.

Dissolved oxygen and sulfates are not monitored or controlled in the CCCW systems. However, these parameters are monitored at appropriate points during the production of make-up water in the Water Treatment Plant. Water Treatment Plant effluent is also monitored for total conductivity to ensure that unacceptable levels of ionic species are not introduced via make-up water. Finally, any dissolved oxygen introduced via make-up water is expected to be rapidly depleted. Without a significant ingress source, dissolved oxygen concentrations do not require control (EPRI TR-107396).

Control of ionic species which disrupt the passive oxide layer found on stainless steels, monitoring of dissolved oxygen in the make-up water, and pH adjustment effectively eliminate corrosion as an aging effect for stainless steels in these systems.

FNP and industry wide operating experience confirm that pitting and crevice corrosion of austenitic stainless steels has not been an issue of concern. FNP monitors for corrosion in closed-cycle cooling water systems. Visual inspections of selected components are performed when they are opened for maintenance. These inspections have consistently shown no visible corrosion. Reviews of FNP operating experience do not indicate a susceptibility to loss of material in stainless steel in a closed cooling water environment.

Conclusion:

Industry and plant-specific operating history has demonstrated the Water Chemistry Control Program has effectively controlled loss of material due to corrosion of stainless steel components exposed to borated water, treated water, and closed cooling water. Therefore additional one-time inspections of stainless steel Auxiliary Systems components for loss of material due to corrosion are not considered necessary.

RAI 3.3-11

Loss of material due to general, pitting, crevice, microbiologically influenced corrosion and biofouling is a plausible aging effect for stainless steel and carbon steel in the raw water environment or stainless steel exposed to lube oil that may be contaminated with water. In the LRA, the applicant credited the One-Time Inspection AMP for managing the loss of material aging effect on stainless steel and carbon steel piping and valve bodies exposed to raw water environment or stainless steel components exposed to lube oil that may be contaminated with water. However, the staff notes that the One-Time Inspection Program is intended for use as a verification AMP to check the degree of aging of components when significant aging is not expected, while periodic inspections are more appropriate if aging effects can reasonably be expected to occur. The applicant is requested to provide justification for why the One-Time Inspection is appropriate for managing the identified aging effect.

Response:

Stainless Steel Exposed to Lubricating Oil w/ Potential Water Contamination (RCP Oil Collection System):

In Section 3.3 (Aging Management of Auxiliary Systems) of the LRA, SNC credits the One-Time Inspection (OTI) Program to manage stainless steel components in a lubricating oil environment for the RCP oil collection system. The RCP oil collection system is an "open" oil leakage collection system which is designed to collect potential external leakage from the RCP motor lubricating oil system. The RCP oil collection system includes "open" drip pans and therefore the presence of water contamination from the general area environment was assumed to be plausible although significant contamination is not anticipated. Stainless steel is very resistant to general corrosion, pitting, crevice, and MIC and biofouling is not expected. Additionally, the FNP operating experience review did not identify any applicable aging issues. Therefore, SNC considers use of the OTI Program for the stainless steel components in the RCP oil collection system appropriate to confirm no significant aging is occurring.

Stainless Steel And Carbon Steel Piping And Valve Bodies Exposed To Raw (Unmonitored) Water Environment:

SNC credits the OTI Program for the following carbon steel and stainless steel components that are exposed to raw water:

- control room air conditioning cooling coil units,
- drain piping and valves in the Liquid Waste and Drains system, and
- piping, valves, and a tank in the Potable and Sanitary Water System.

These systems operate at low pressure and ambient temperature. While some degree of corrosion is expected in these components, SNC does not expect significant aging to occur in these components that could cause loss of component intended function(s). If significant aging is discovered, appropriate corrective action will be initiated to ensure the intended functions are maintained during the period of extended operation. Specific discussion of each item follows.

Control Room Air Conditioning Cooling Coil Units: The raw water environment for these units is moisture/condensation that may form on the units. The units are designed for this environment with the selection of materials intended to provide reliable service. The carbon steel that may potentially be wetted is galvanized. The One-Time Inspection Program is appropriate to inspect the unit and confirm significant aging is not occurring.

Drain Piping And Valves In The Liquid Waste And Drains System: The drain piping and valves in the liquid waste and drains system operate at low pressure and temperature and are used on an intermittent basis. Typically the piping is "dry", however the LRA environment assumes the most limiting environment of "raw water." This raw water is better characterized as an "unmonitored and uncontrolled water" source. The One-Time Inspection Program is appropriate to inspect and confirm significant aging is not occurring in the drain piping and valves.

Piping, Valves, and Tank In The Potable And Sanitary Water System: Although described as "raw water," the potable and sanitary water system water is "well water or potable water" as described in LRA Table 3.0.4-1. The water is taken from deep wells and run through clarifiers. Operating experience with these types of systems does not indicate SNC should expect significant aging. The One-Time Inspection Program is appropriate to inspect and confirm significant aging is not occurring.

These systems operate at low pressure and ambient temperature. While some degree of corrosion is expected in these components, SNC does not expect significant aging to occur in these components. SNC will use the One-Time Inspection Program to determine if corrosion has occurred during the current operating term to such an extent that additional actions might be required during the renewal term. Such actions could include additional inspections, component replacements, or other appropriate measures.

RAI 3.3-12

In Tables 3.3.2-10 and 3.3.2-11 of the LRA, for copper alloy components exposed to inside environment, the LRA identified loss of material as the aging effect requiring management (AERM) for some components (cooling units), but concluded that there are no aging effects for other components (Pitot tubes). The applicant is requested to justify the different AMR results for the same material and environment combination.

Response:

The aging management review for copper alloy components exposed to an inside environment evaluates the potential for water to pool on the surfaces (external) and the likelihood that the components will be wetted. Copper materials that could be exposed to repeated wetting or the pooling of water can experience loss of material.

The cooling coils and fins for HVAC units are examples of locations where the external surfaces are likely to be wetted regularly due to condensation. SNC has identified loss of material as an aging effect requiring management for copper alloy components in an inside environment with a potential for significant wetting or water pooling. The pitot tubes are an example of a component whose external surface is not likely to be wetted or exposed to pooled water in the "Inside" environment. As such, SNC has not identified loss of material as an aging effect requiring management in an inside environment for that component.

RAI 3.3-13

The applicant stated that compressed air system (Table 3.3.2-7) and emergency diesel generator system (Table 3.3.2-15) components in a dried gas environment have no applicable aging effects. A dried gas environment is described by the applicant as containing non-condensable vapor with a very limited percentage of moisture present and that dried gases include compressed air (downstream of air dryers), and bottled gases such as carbon dioxide, hydrogen, nitrogen, oxygen and refrigerants. The staff agrees with this position if the gas is relatively dry and moisture-free. However, moisture present in gas may be a major contributor to aging degradation. The applicant is requested to discuss the measures for maintaining and verifying the dryness level in the gas environment, including the acceptance criteria and their basis.

Response:

Dry bottled gases are produced by compressed gas vendors and meet manufacturer's standards as well as industry standards for moisture content. Typical dew points range from -90° F to -80° F or approximately 3.5 ppm water vapor to 7.8 ppm water vapor. It is also noted that purity levels for bottled gasses typically run in the 99.999% to 99.50% range. Impurities represent those constituents in the cylinder that are not pure gas and a portion of this "impurity" includes the small amount of water vapor. It can be seen that the water vapor potential is extremely low for these dry bottled gases and that any moisture carryover into plant systems is insignificant.

Air dryers are located in compressed air systems to provide dry air for the air distribution network, or in the case of the emergency diesel generators (EDGs), for the air start header(s). Air dryers and receivers are natural collection points for moisture and are automatically drained of water and also periodically drained by manual actions to assure no significant amounts of water enter the systems. The gas is relatively dry and moisture free downstream of the air dryer.

Desiccant in the EDG air start air dryers is replaced every 3 months, regardless of condition. The compressed air system has redundant air dryers installed that operate with continuous regeneration and are designed to reduce the dew point of the air to -40° F. The dew point is measured on the air dryers every 6 months and desiccant is inspected and replaced yearly if needed in the compressed air system air dryers. The quality of compressed air is periodically monitored at selected locations. The acceptance criteria for dew point is that it must be at least 18° F below the minimum temperature to which the instrument air system is exposed.

In summary, the operating history at FNP does not indicate any significant aging degradation in systems exposed to a "dried gas" environment. The design features (dry bottled gases and air dryers), actions taken (monitoring of dew points and replacement of dessicant), and operating history provide reasonable assurance that the air systems' internal environment where indicated in the LRA as "dried gas" is relatively dry and moisture free and have no applicable aging effects requiring management for the period of extended operation.

RAI 3.3-14

For several auxiliary systems such as oil-static cable pressurization system and emergency diesel generator system, the applicant concluded that there are no applicable aging effects for components in lube oil environment. The staff agrees with this position if the lube oil is relatively dry and water-free. However, moisture present in lube oil maybe a major contributor to aging degradation. During operations, moisture may accumulate even though 'fresh' oil maybe relatively dry and water-free initially. The applicant is requested to describe the measures for maintaining and verifying the dryness of the lube oil, including the acceptance criteria and their basis.

Response:

SNC concluded the lubricating oil environment for the following auxiliary systems (LRA Section 3.3) are not potentially water contaminated:

- OCCW - air compressor lubricating oil;
- EDG - lube oil systems for the Emergency Diesel Generators;
- COS - Oil-Static Cable Pressurization System.

Lubricating oil systems are typically closed systems that have little potential for ingress of contaminates unless a component failure occurs. License renewal does not assume component failures as a means to establish the conditions necessary for aging to occur. Water contamination of lubricating oil in a "closed" lubricating oil system is event-driven, and addressed by corrective action. FNP operating experience confirms that lubricating oil systems are not susceptible to loss of material caused by water contamination.

The activities described below are routine operating and maintenance activities which are not credited as aging management programs. Oil levels are checked daily during operator rounds for the affected systems. Gross water contamination of lubricating oil can be visually identified by increased oil level or the oil presenting a “milky” appearance.

<u>OCCW - Air Compressor Lubricating Oil</u>
The subject air compressors are in scope for license renewal as part of FNP's 10 CFR 50.48 compliance licensing basis (10 CFR 50 Appendix R safe shutdown). The lubricating oil in these air compressors is changed annually during the compressor overhaul.

<u>EDG - Lube Oil Systems for the Emergency Diesel Generators</u>
Emergency diesel generator (EDG) oil samples are obtained and analyzed with acceptance criteria established in accordance with manufacturer’s or user’s group recommendations. Lubricating oil may be either re-used or replaced with new oil as required by sample results. Operating conditions in the EDGs preclude accumulation of significant moisture in the lubricating oil from environmental sources. The high operating temperature of the EDGs would vaporize any moisture in the oil and it would be exhausted by the crankcase vacuum pump. When the EDG is not operating, the keep-warm system maintains the lube oil at temperatures above the ambient conditions.

COS - Oil-Static Cable Pressurization System

The oil-static cable pressurization system is designed to prevent moisture intrusion. The system operates to maintain a continuous pressure of >180 psig downstream of the oil pumps. Upstream of the oil pumps a nitrogen overpressure of 8 psig is maintained on the storage tanks to prevent intrusion of moisture and other contaminants. Both pressures are monitored during operator rounds, and both have low pressure alarms to ensure prompt corrective action for low pressure conditions. There is no credible mechanism for moisture to accumulate in this system. However, moisture content is one of the parameters monitored and trended for this system. Sample results typically run 10 ppm or less.

RAI 3.3-15

Several auxiliary systems, such as spent fuel pool cooling and cleanup system, closed-cycle cooling water system, sampling system, and CVCS, have heat exchangers that are cooled by the closed-cycle cooling water system. It is not clear in the LRA whether inspections and monitoring will be performed on the subcomponents (e.g., tube sheets, tubes, etc.) exposed to closed-cycle cooling water. The applicant is requested to clarify the types of inspections or monitoring that will be performed on the heat exchangers.

Response:

The specific aging management strategy applied to each auxiliary systems heat exchanger component (e.g., tube sheets, tubes, etc., as noted in the Tables) is provided in the LRA 3.3.2-xx series of Tables. All heat exchanger components in contact with closed-cycle cooling water (CCCW) are managed by the Water Chemistry Control Program. The preventive nature of the Water Chemistry Control Program is considered to be adequate to manage the effects of corrosion, selective leaching and cracking through the period of extended operation for heat exchanger components exposed to a closed-cycle cooling water environment. While inspections are generally considered unnecessary, SNC has included the materials most susceptible to corrosion in the CCCW environment within the scope of the One-Time Inspection Program (OTI).

Carbon steel, cast iron, and copper alloy components in a CCCW environment, including heat exchanger components, are included in the scope of the One-Time Inspection Program to verify the effectiveness of the Water Chemistry Control Program in managing loss of material due to corrosion. One-time inspections for stainless steel components in a CCCW environment were determined to be unwarranted as a result of the inherent corrosion resistance of stainless steels and the controlled CCCW environment (refer to our response to RAI 3.3-10 for additional discussion).

FNP has performed numerous inspections, both visual and eddy current, on heat exchangers in the CCCW environment. These inspections have not identified any significant age-related degradation from corrosion or cracking. In addition, FNP has an ongoing effort to visually inspect selected closed-cycle cooling water system components when they are opened for maintenance. These visual examinations have consistently shown no significant corrosion or other age-related degradation for the CCCW environment.

The FNP operating experience review for the LRA identified loss of material due to wear for the component cooling water (CCW) heat exchangers tubes. Wear has occurred at the tube-to-support plate interface in the vicinity of the shell-side (CCCW) inlet and outlet. This wear has been attributed to flow-induced vibration of the tubes. In addition to plugging of tubes and operational changes, corrective actions include ongoing eddy current testing of the heat exchanger tubes as part of the Service Water Program.

To minimize confusion, the Service Water Program was only associated with the service-water-side of the CCW heat exchanger tubes in the LRA (Table 3.3.2-5). However, the Service Water Program is also credited for aging management of the CCCW-side of the tubes for loss of material due to wear.

In summary, the FNP-specific operating experience confirms the aging management strategies described are adequate to manage applicable aging effects through the period of extended operation.

RAI 3.3-16

The LRA does not identify cracking as an applicable AERM for bolting in auxiliary systems. LRA Table 3.3-1, item number 24, states that cracking is not applicable to bolting due to material selection and sound maintenance practices (control of torque, proper lubricants, and sealing compounds); however, the susceptibility to cracking is determined primarily by the bolting material and the operating temperature. In order to justify that cracking is not an applicable AERM, the applicant is requested to provide the reasons by identifying the bolting materials and the yield strength of the bolting procured for the auxiliary systems within the scope of license renewal, and the operating temperatures of the bolting. For high strength bolting (yield strength greater than 150 ksi), provide additional justification for the conclusion that cracking is not an applicable AERM, or provide an appropriate AMP to manage cracking.

Response:

Carbon steel and alloy steel bolting materials used in FNP auxiliary systems within the scope of license renewal typically have low operating temperatures; however, some applications (e.g., portions of CVCS and Sampling System) can operate at temperatures as high as RCS temperatures.

The bolting materials used in the FNP auxiliary systems bolted connections are:

1. ASME SA-307 and ASTM A307 Grade B carbon steel bolts with a maximum specified tensile strength of 100 ksi and,
2. ASME SA-193 and ASTM A193 Grade B7 alloy steel bolts with specified minimum yield strengths up to 105 ksi;

ASME SA-307 / ASTM A307 Grade B carbon steel bolts are not considered high strength bolting since the upper limit on tensile strength of 100 ksi assures that the maximum bolt yield strength will be less than 100 ksi. Based on this yield strength, these bolts are not susceptible to SCC in normal ambient environments. This conclusion is supported by both FNP and industry-wide operating experience.

ASME SA-193 / ASTM A193 Grade B7 bolts have a minimum specified yield strength of 105 ksi, which is well below the threshold value of 150 ksi. Bolting fabricated in accordance with SA-193 could reasonably be expected to have an actual yield strength less than 150 ksi. However, since no maximum yield strength is specified for this material, it cannot be assured that the actual yield strength will not exceed the 150 ksi limitation for SCC susceptibility set forth by the Staff. SNC considers several mitigating factors to exist which, when considered together indicate that SCC of ASME SA-193 / ASTM A193 Grade B7 bolts need not be considered an aging effect requiring management at FNP:

Although there have been a few instances of cracking of bolting in the industry due to SCC, these have been attributed to high yield stress materials and contaminants, such as the use of lubricants containing molybdenum sulfide (MoS_2). Laboratory tests indicate that hydrogen sulfide (H_2S) may result from MoS_2 decomposition which causes SCC in carbon and alloy steel fasteners. A review of industry failure databases and NRC generic communications supports the fact that a combination of material selection, control of contaminants, and proper maintenance and torquing procedures have been effective in eliminating the potential for SCC of bolting materials.

1. Material Selection – EPRI NP-5769, "Degradation of Bolting in Nuclear Power Plants," April 1988 indicates that susceptibility to SCC is minimized through selection of materials having specified minimum yield strengths less than 150 ksi. EPRI NP-5769 indicates the only industry failures of bolts in this category were related to poor quality control and were detected during plant construction. The auxiliary systems bolting materials meet this criteria. A minimum yield strength below 150 ksi does not, in and of itself, preclude SCC from occurring (since actual yield strength can be above the threshold value); however, it reduces the potential.

2. Control of Contaminants – In general, environmental conditions that could lead to SCC of bolting are not expected to occur in non-Class 1 components. Most bolting at FNP is normally in a dry environment and coated with a lubricant. For borated water systems, the Borated Water Leakage Assessment and Evaluation Program ensures leaks are detected promptly and corrective actions taken. For bolting located outdoors, the atmosphere is mild in terms of corrosive contaminants (rural environment and remote from coastal regions). Rain tends to wash off contaminants instead of concentrating them. Within the industry, SCC failures of quenched and tempered alloy steel bolting, such as SA-193 Grade B7 bolts, have many times been associated with the use of lubricants that may decompose into SCC-inducing contaminants, most notably MoS_2. FNP has not used lubricants containing MoS_2 and procedural controls are in place at FNP to prevent the use of lubricants containing potentially detrimental species such as chlorides and sulfates.

3. Control of Bolt Preload – Excessive bolt stresses have resulted in SCC failures throughout the industry. Proper control of bolt preload through sound bolt torquing practices has been shown to prevent excessive preload and thereby minimize the potential for SCC failures. At FNP, procedural controls are in place to assure that proper bolt torquing practices are used.

The potential for SCC of bolting materials has been addressed at FNP in response to several industry communications including NRC IE Bulletin 82-02, INPO SOER 84-5, and EPRI guidance documents. The bolting materials used, lubricant/ contaminant controls, and sound bolt torquing practices have been effective at eliminating this aging effect. A review of recent FNP operating history performed for development of the FNP LRA did not identify any instances of SCC in auxiliary systems bolting which includes ASTM SA-193 / ASTM A193 Grade B7 fasteners. Additionally, a review of recent NRC generic communications did not identify any recent bolting failures attributable to SCC.

Therefore, cracking due to SCC is not an aging effect requiring management for the carbon steel and alloy steel bolting materials used in FNP auxiliary systems.

RAI 3.3-17

A. Referring to Table 3.3-1 of the LRA, item 3.3.1-11 states in the discussion that the FNP Structural Monitoring Program (Appendix B.4.3) will manage loss of material of the carbon steel portions of the new fuel storage racks. Discuss applicable non-carbon steel materials (e.g., aluminum, stainless steel, etc.) that are used in FNP's new fuel rack assemblies, their environments, FNP specific aging related operating experience, and the results of their aging management review. Also, explain why these new fuel rack assemblies are not explicitly listed in section B.4.3.5, Program Scope, of the FNP's Structural Monitoring Program.

Response:

The Auxiliary Building New Fuel Storage Area is adjacent to the Spent Fuel Pool (SFP) area, but is a separate area designed for dry storage of new fuel assemblies prior to transfer into the SFP. The new fuel storage rack assemblies are located in an inside (dry) environment. The "Inside" environment is described in section 3.0.4 of the LRA. Each rack is composed of individual vertical cells that can be fastened together in any number to form a module that can be firmly bolted to the floor of the new fuel storage area. All surfaces that come into contact with the fuel assemblies are made of austenitic stainless steel, whereas the supporting structure is carbon steel. The component type includes the structural steel rack frame members, stiffeners, and anchors into the reinforced concrete building structure.

A review of FNP operating experience performed for development of the FNP LRA indicates that there has been no age-related degradation of the stainless steel material in an inside (dry) environment.

A spaces approach is used for performing the Structural Monitoring Program (SMP) inspections. Therefore, the Structural Monitoring Program scope in section B.4.3.5 lists only the in-scope structure (e.g., Auxiliary Building) but not every component located inside the structure. New fuel rack assemblies are a structural component type located in the Auxiliary Building and thus are inspected by the program.

RAI 3.3-17

B. Referring to Table 3.3-1 of the LRA, item 3.3.1-13 states in the discussion that the spent fuel storage racks are not considered susceptible to stress corrosion cracking since the temperature of the borated water in the spent fuel pool is normally less than this threshold temperature for SCC. Elaborate on FNP's use of the phrase: "...normally less than this threshold temperature for SCC," define the threshold temperature referred to therein, explain expected or applicable abnormal conditions implied in the phrase, and discuss applicable SCC related operating experience of FNP spent fuel storage racks and associated valves.

Response:

FNP applies a conservative threshold temperature of 140 °F for initiation of SCC in austenitic stainless steel components exposed to borated water. Extensive industry data based on actual operating experience and laboratory testing indicate that initiation of SCC is unlikely to occur at temperatures less than 140 °F unless the materials are sensitized and exposed to harsh marine wet – dry cycling conditions. This SCC threshold limit is consistent with EPRI TR 1003056, "Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Revision 3," November 2001.

FNP maintains a 105 °F operational temperature limitation on the spent fuel pool except during refueling outages. A 130 °F operational temperature limitation is maintained during refueling outages. Actual operating temperatures in the spent fuel pool are below these operational limits. To date, there have been no fuel pool temperature excursions exceeding 140 °F. Conservatively postulated abnormal core offload or accident scenarios could potentially exceed the 140 °F threshold for initiation of SCC (FNP UFSAR, Rev. 17, Section 9.1.3.1.1) but are not representative of actual operation.

A review of FNP operating experience performed for development of the FNP LRA did not identify any SCC-related experience associated with the spent fuel storage racks or FNP Spent Fuel Pool Cooling and Cleanup System austenitic stainless steel components.

Therefore, existing industry data and FNP specific operating experience indicate that cracking due to SCC is not an aging effect requiring management for the FNP spent fuel storage racks and FNP Spent Fuel Pool Cooling and Cleanup System components exposed to borated water.

3.3.2.1.5 Open-Cycle Cooling Water System

RAI 3.3.2.1.5-1

The LRA states the Buried Piping and Tank Inspection Program is used to manage buried carbon steel and buried stainless steel piping in this system. However, the scope of the Buried Piping and Tank Inspection Program only includes buried carbon steel piping and tanks. The applicant is requested to clarify which AMP will be used to manage the buried stainless steel piping. If the Buried Piping and Tank Inspection Program will be used, provide the appropriate updates to the 10 elements or explain how the GALL program will be used for stainless steel components.

Response:

In addition to buried carbon steel piping and tank components the LRA states buried stainless steel and buried copper alloy piping components (Fire Protection System LRA Table 3.3.2-13) will be age managed at FNP with the Buried Piping and Tank Inspection Program. This program should have included buried stainless steel and copper alloy piping components in the program scope. The Buried Piping and Tank Inspection Program has been updated to include buried stainless steel and copper alloy piping components.

FNP's LRA Appendix A.2.16 and Appendix B.5.4 are corrected as follows (***changes are in bold italics***):

LRA Appendix A.2.16 - Buried Piping and Tank Inspection Program

The new Buried Piping and Tank Inspection Program will be used to manage the loss of material from external surfaces of ***in-scope*** pressure-retaining buried carbon steel piping and tanks ***and buried stainless steel and copper alloy piping*** during the extended period of operation. Administrative controls and procedures will be put in place to ensure that buried piping and tanks will be inspected when they are excavated for maintenance or when those components are exposed for any reason. This new program will be implemented prior to the period of extended operation.

This program will be consistent with the 10 attributes of the aging management program described in NUREG-1801, Section XI.M34, with the exception that it also includes provisions for inspection of buried stainless steel and copper alloy piping.

LRA Appendix B.5.4 - Buried Piping and Tank Inspection Program

B.5.4.1 Program Description

The new FNP Buried Piping and Tank Inspection Program will be used to manage loss of material from the external surfaces of pressure-retaining buried carbon steel piping and tanks ***and buried stainless steel and copper piping components.*** Preventive measures have been put in place in accordance with standard industry practices for external coatings and wrappings. Buried piping and tanks will be inspected when they are excavated for maintenance or when those components are exposed for any reason. FNP will implement this new program prior to the period of extended operation.

The scope of the FNP Buried Piping and Tank Inspection Program includes the external surfaces of the following buried components:

- Service water piping
- Emergency diesel generator fuel oil storage tanks and fuel oil transfer piping
- Fire protection piping
- Oil-static Cable Pressurization System buried components from the high voltage to the low voltage switchyard

B.5.4.2 NUREG-1801 Consistency

The FNP program attributes will be consistent with those described in NUREG-1801, Chapter XI.M34 ***except as described in B.5.4.3.***

B.5.4.3 Exceptions to NUREG-1801

- ***Buried stainless steel and copper alloy piping components are also included in the scope of the program. The buried stainless steel and copper alloy components are not normally wrapped or coated, however, these materials have a natural resistance to corrosion in the buried environment.***
- ***Inspections are performed when the components are excavated for maintenance or for any other reason including investigation of a potential leak.***
- ***For uncoated/unwrapped piping, visual inspection will also be used to examine the external surfaces to confirm that no significant (detrimental) loss of material has occurred.***
- ***Any significant loss of material in piping will be reported and evaluated according to site corrective actions procedures.***

B.5.4.4 Enhancements

- None ***(This is a new program.)***

B.5.4.5 Operating Experience

This is a new program. Therefore, no programmatic operating experience has been gained. Leaks in buried piping systems at FNP have typically resulted from localized damage to the external coating/wrapping on carbon steel piping, such as from a rock or mechanical damage during installation. FNP has been successful at detecting these leaks prior to any loss of system function.

B.5.4.6 Conclusion

Implementation of the new FNP Buried Piping and Tank Inspection Program prior to the period of extended operation will provide reasonable assurance that the effects of aging on the pressure-retaining function of those components will be maintained during the period of extended operation.

3.3.2.1.7 Compressed Air System

RAI 3.3.2.1.7-1

The LRA credits the One-time Inspection Program (B.5.5) to manage the aging effect of loss of material of several components in air/gas (wetted) environment. The staff notes that one-time inspections are used for verification when significant aging is not expected. The staff also observes that for comparable components/materials/environments/AERM in the compressed air system, the GALL recommends the use of GALL Program XI.M24, "Compressed Air Monitoring," which uses, in part, periodic inspection/testing of components. The applicant is requested to justify why a one-time inspection is adequate in lieu of periodic inspection/testing of components for the compressed air system components in air/gas (wetted) environment.

Response:

The new FNP One-Time Inspection Program will be used for cases where either (a) an aging effect is not expected to occur but there is insufficient data to completely disprove the effect, or (b) an aging effect is occurring slowly enough to not affect the component or structure intended function during the period of extended operation, and therefore will not require additional aging management.

The One-Time Inspection Program will provide for an inspection of a sampling of compressed air system components upstream of and including the air dryers to determine if any significant corrosion is occurring within these components. Low points in this portion of the system are routinely drained to prevent moisture accumulation. Loss of material is expected to occur slowly enough to not affect the component intended function during the period of extended operation. The program includes an evaluation to determine the need for follow-up examinations to monitor the progression of any aging degradation if found during the inspection.

Please note past NRC acceptance at V.C. Summer and Robinson Nuclear plants for one-time inspections in similar environments.

3.3.2.1.8 Chemical and Volume Control System

RAI 3.3.2.1.8-1

The loss of fracture toughness/thermal aging embrittlement may be an applicable aging effect for cast austenitic stainless steel (CASS) components in high temperature borated water environment. The applicant is requested to clarify whether this is an applicable aging effect for the CASS components (such as the regenerative heat exchanger) in the CVCS and, if applicable, provide an aging management program.

Response:

Only components operating at temperatures exceeding 482 °F need be screened for susceptibility to thermal embrittlement. Within the CVCS system, the only austenitic stainless steel castings meeting this operating temperature requirement are the regenerative heat exchanger shells and channel heads.

In a May 19, 2000 letter Grimes (NRC) to Walters (NEI), "License Renewal Issue No. 98-0030, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Components," the staff evaluation outlined an acceptable method for screening cast austenitic stainless steel components for susceptibility to thermal embrittlement. FNP applied the screening criteria contained in this staff evaluation to the CVCS system regenerative heat exchanger shells and channel heads. These castings were determined to be low in molybdenum content (< 0.5% by wgt.) and to be centrifugally cast. Using the screening criteria contained in Table 2 of the staff evaluation, these castings are not susceptible to thermal embrittlement, regardless of casting ferrite number.

3.3.2.1.8 Chemical and Volume Control System

RAI 3.3.2.1.8-2

For stainless steel boric acids tanks in air/gas (air space) environment, the applicant is requested to clarify whether the interior surface of the tank is subjected to periodic drying and wetting due to fluid level changes. If so, clarify whether this may lead to concentrated level of boric acid leading in turn to aging degradation, and provide information on how to manage this aging effect.

Response:

The FNP CVCS boric acid tanks utilize a bladder and loop seal design to prevent the ingress of oxygen into the CVCS system. Therefore, fluid level changes do not result in the type of periodic wet – dry cycling that potentially could produce concentrated levels of boric acid. Due to the bladder, the air space of the boric acid tanks is not exposed to wetting with borated water.

Additionally, the FNP CVCS system boric acid tanks are fabricated from 300 series wrought austenitic stainless steels. Industry material screening tests indicate that this material is relatively unaffected by exposure to boric acid, boric acid spray, and boric acid crystals.

3.3.2.1.9 Control Room Area Ventilation System

RAI 3.3.2.1.9-1

Loss of material due to galvanic corrosion may be a susceptible aging effect on the contact of aluminum fin and copper tubes of the heat exchangers that are exposed to wetted air/gas environment. However, it was not clear in the LRA if galvanic corrosion is included in the One Time Inspection Program. The applicant is requested to clarify whether the One-Time Inspection Program will manage the galvanic corrosion on the contact area of aluminum fin and copper coils.

Response:

Per LRA Table 3.3.2-9, loss of material is an aging effect requiring management (AERM) for the aluminum fins, which are in contact with the copper direct expansion cooling tubes inside the control room air-conditioning cooling coils (heat exchangers). Due to the lower galvanic potential of the aluminum fins relative to the copper tubing, loss of material for the aluminum fins due to galvanic corrosion in the wetted air/gas environment is an AERM in the vicinity where the two materials are in contact. Therefore, the aluminum fins are conservatively included within the scope of the One-Time Inspection Program for loss of material due to galvanic corrosion. However, galvanic corrosion is not expected to be significant. Cooling coils constructed of copper tubes and aluminum fins have proved reliable in HVAC applications. The One-Time Inspection Program will be used to verify that significant loss of material is not occurring, including that from galvanic corrosion.

3.3.2.1.14 Diesel Fuel Oil System

RAI 3.3.2.1.14-1

In LRA Table 3.3.2-14 for diesel fuel oil system, the applicant identified loss of material as the aging effect for carbon steel, alloy steel, and stainless steel pipes exposed to inside (protective trench) environment. The LRA does not define the protective trench environment. The applicant is requested to provide a description of this environment and discuss the differences from the regular inside environment (in particular as related to aging mechanisms and aging effects). For managing this aging effect, the LRA identifies the External Surface Monitoring Program for carbon steel and alloy steel piping, whereas it uses One-Time Inspection Program for stainless steel piping. The applicant is requested to provide the basis for using different AMPs.

Response:

The piping trenches in the Emergency Diesel Generator bays are located in the Inside environment associated with the Diesel Generator Building. The trenches are recessed in the floor and therefore are a low point that could collect any spills or leaks occurring in the area. These piping trenches are covered therefore a visual inspection of the conditions in the trenches was not performed prior to submitting the LRA. While the piping that runs in these trenches is supported off the floor by spacers at regular intervals, SNC felt it prudent to examine the piping in the trenches to confirm the conditions in the trenches (evidence of spills or immersion) and any impact on the installed piping. Therefore, a distinct environment of "Inside - In protective trench" was created to ensure aging management program(s) were specified that would inspect the condition of the external surfaces of the piping in the trenches.

In the LRA for mechanical systems, the Exterior Surfaces Monitoring Program is utilized to inspect carbon and low alloy steel external surfaces in an "Inside" environment and therefore was appropriate and consistent for aging management of the external surfaces of the carbon and low alloy piping in the trenches. However, stainless steel external surfaces in an "Inside" environment do not have an aging effect requiring management. Stainless steel is inherently corrosion resistant. Therefore, the One-Time Inspection Program is appropriate to perform an inspection to confirm that detrimental aging of stainless steel piping in the trenches is not occurring.

3.3.2.1.14 Diesel Fuel Oil System

RAI 3.3.2.1.14-2

For the carbon steel vent cap and screen in an outside environment, the LRA credits the One-Time Inspection Program for managing the loss of material. The One-Time Inspection Program is intended for components where no significant aging is expected. Since general corrosion is expected to occur in carbon steel in an outside environment, periodic inspection may be more appropriate than a one-time inspection. The applicant is requested to provide additional justification for use of a one-time inspection in lieu of periodic inspection for this component.

Response:

SNC is in agreement that periodic inspection is more appropriate for managing loss of material in carbon steel components exposed to an "Outside" environment. The LRA Table 3.3.2-14 line item for the vent cap and screen is in error.

The carbon steel "Vent Screen" for the diesel generator fuel oil storage tanks has an exterior environment of "Outside." The External Surfaces Monitoring Program will provide periodic inspection of the external surfaces in an outside environment. The interior environment of the "Vent Screen" is predominately the same environment as the vapor space of the fuel oil storage tanks. The vapor space of the fuel oil storage tanks has been shown by inspection to be free of detrimental aging effects. Therefore a one-time inspection in lieu of periodic inspection is appropriate for the interior of the Vent Screen component exposed to an "Air/Gas" environment.

The "Vent Screen" line item in LRA Table 3.3.2-14 should have read as follows:

Component Type *GALL Reference*	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
Vent Screen (vent cap and screen)	Debris Protection	Carbon Steel	Outside	Loss of Material	External Surfaces Monitoring Program			J
			Air / Gas	Loss of Material	One Time Inspection Program			

3.3.2.1.15 Emergency Diesel Generator System

RAI 3.3.2.1.15-1

The LRA identifies that copper alloy in a closed cooling water environment is subject to loss of material. For the heat exchanger components (Table 3.3.2-15, p.3.3-119), the LRA credits the One -Time Inspection Program in conjunction with the Water Chemistry Control Program for aging management. However, for piping (Table 3.3.2-15, p.3.3-122), the LRA only credits the Water Chemistry Control Program. The applicant is requested to discuss the different aging management of apparently similar material/environment/AERM.

Response:

The One Time Inspection Program should have been listed in conjunction with the Water Chemistry Controls for the Emergency Diesel Generator cooling water system copper alloy piping and valve bodies in the closed cooling water environment in Table 3.3.2-15. This aging management program appears to have been inadvertently omitted. The SNC aging management results utilize the One Time Inspection Program to confirm the effectiveness of the Water Chemistry Control Program in controlling loss of material for copper alloy components in the closed-cycle cooling water environment.

3.3.2.1.15 Emergency Diesel Generator System

RAI 3.3.2.1.15-2

In LRA Table 3.3.2-15 for emergency diesel generator system, for most copper alloy or stainless steel components exposed to an air/gas (wetted) environment, the LRA identifies loss of material as the applicable aging effect and credits the One-Time Inspection Program for aging management. However, for ducts and fittings in the intake/exhaust system, and the pipes and valve bodies in the air start system, the LRA also identifies cracking as an applicable aging effect, and credits the One-Time Inspection Program for aging management. The applicant is requested to explain the difference in aging effects for apparently similar material/environment combinations. If the cracking is due to cyclic loading of specific components, justify the use of the One-Time Inspection Program in lieu of periodic inspections, since such cracking may have a long incubation period.

Response:

Stress corrosion cracking (SCC) was identified as an aging effect requiring management for Emergency Diesel Generator (EDG) System stainless steel and copper alloy components in an air/gas (wetted) environment subject to elevated temperatures. For stainless steels, the SNC utilizes a threshold temperature of 140 °F for susceptibility to SCC.

SCC was determined to be a potential aging effect for stainless steels in the EDG exhaust system's air/gas (wetted) environment. The air/gas (wetted) environment elevated temperatures during EDG operation produced by the high temperature exhaust gases. These exhaust gases include water vapor and various corrosive combustion products. SNC does not expect SCC to actually occur given the limited number of times that each diesel generator is operated over the course of 60 years of plant operation and the proximity of the exhaust temperatures to the threshold temperature for SCC. However, SNC has insufficient data to rule out the possibility of the aging effect therefore it is prudent to perform a one-time inspection to assure that cracking is not occurring.

SCC is not an applicable aging effect for the stainless steels in the EDG intake system's air/gas (wetted) environment. The EDG intake system operates at ambient temperatures and is not subject to elevated temperatures. Cracking should not have been indicated in LRA Table 3.3.2-15 for the stainless steel ducts and fittings in the EDG intake system.

SCC was determined to be a potential aging effect for stainless steels and copper alloys in portions of the EDG air start system exposed to the air/gas (wetted) environment with elevated temperatures. Specifically, air exiting the compressors will heat the downstream components. The one-time inspection is specifically meant to examine the inlet piping for the air receivers on the 1-2A emergency diesel generator. The air start subsystem for this diesel generator does not include an after cooler/air dryer assembly. As such, potentially moist air at temperatures above 140 °F could be in contact with the in-scope stainless steel and copper alloy components. While SNC does not consider stress corrosion cracking likely, SNC does not have sufficient data (the removal of the after cooler and air drier is a recent modification) to rule out the possibility; therefore, it is prudent to perform a one-time inspection to assure that cracking is not occurring.

3.3.2.1.19 Liquid Waste and Drains

RAI 3.3.2.1.19-1

Crack initiation and growth are susceptible aging effect on stainless steel components exposed to borated water environment. However, this is not identified as a plausible aging effect in the LRA, Table 3.3.2-19, for the stainless steel piping and valve bodies. The applicant is requested to provide technical basis for excluding this plausible aging effect.

Response:

FNP applies a conservative threshold temperature of 140 °F for initiation of stress corrosion cracking (SCC) in austenitic stainless steel components exposed to borated water. Extensive industry data based on actual operating experience and laboratory testing indicate that initiation of SCC is unlikely to occur at temperatures less than 140 °F unless the materials are sensitized and exposed to harsh marine wet – dry cycling conditions. This SCC threshold limit is consistent with EPRI TR-1003056, "Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Revision 3," November 2001.

The in-scope Liquid Waste and Drains components exposed to a borated water environment operate at temperatures less than 140 °F threshold temperature and therefore, SNC has not included this aging effect in Table 3.3.2-19.

3.3.2.1.21 Potable and Sanitary Water System

RAI 3.3.2.1.21-1

Selective leaching is a plausible aging effect for copper alloy components exposed to raw water. However, this aging effect is not identified, in LRA Table 3.3.2-21, for potable and sanitary water system, for the copper alloy piping and valve bodies exposed to raw water. The applicant is requested to provide technical basis for excluding this aging effect.

Response:

Selective leaching is the removal of one element from a solid alloy by corrosion processes, such as the removal of zinc from brass alloys. Copper alloys containing greater than 15% zinc are susceptible to selective leaching. The addition of small amounts of alloying elements such as tin also inhibit selective leaching.

The copper alloy piping exposed to raw water in the Potable and Sanitary Water (P&SW) LRA system is purchased to ASTM B-88, Type L, specifications. This material is 99.9% copper, which is not susceptible to selective leaching.

The copper alloy valve bodies exposed to raw water in the P&SW LRA system is purchased to ASTM B-62 specifications. This material contains less than 15% zinc (specification is 4.0 – 6.0%). This material is also inhibited by the inclusion of 4.0 – 6.0% tin. Therefore, these valve bodies are not susceptible to selective leaching.

In summary, the copper alloy piping and valve bodies in the Potable and Sanitary Water System exposed to raw water are not susceptible to selective leaching so this aging effect was not identified in LRA Table 3.3.2-21.

3.3.2.1.23 Reactor Makeup Water Storage System

RAI 3.3.2.1.23-1

Crack initiation and growth due to Stress Corrosion Cracking (SCC) may be a plausible aging effect on stainless steel and carbon steel exposed to treated water. However, the LRA does not identify this aging effect on any of the stainless steel or carbon steel components exposed to treated water in the reactor makeup water storage system. The applicant is requested to provide technical basis for excluding this aging effect for the stainless steel or carbon steel components exposed to treated water.

Response:

Stainless Steel
FNP applies a conservative threshold temperature of 140 °F for initiation of SCC in stainless steel components exposed to borated water. Extensive industry data based on actual operating experience and laboratory testing indicate that initiation of SCC is unlikely to occur at temperatures less than 140 °F unless the materials are sensitized and exposed to harsh marine wet – dry cycling conditions. This SCC threshold limit is consistent with EPRI TR-1003056, "Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Revision 3," November 2001.

The Reactor Makeup Water System borated water chemistry is managed by the Water Chemistry Control Program and operates at temperatures less than 140 °F. Therefore, SNC has concluded that SCC is not a potential aging mechanism for stainless steel components in this system.

Carbon Steel
For carbon steel and alloy steel, the EPRI Mechanical Tools document only identifies SCC as potential aging mechanism where nitrate corrosion inhibitors are utilized. However, nitrate inhibitors are not used in the reactor makeup water system (treated water environment). Therefore, SNC has concluded that SCC is not a potential aging mechanism for carbon and alloy steel components in this system.

3.3.2.1.24 Sampling System

RAI 3.3.2.1.24-1

LRA Table 2.3.3.24 states that "exchange heat" is an intended function of the sampling system heat exchanger tubes. The tubes may be subject to buildup or deposit of fouling or other degradation that would result in a loss of heat exchange function; however, this aging effect is not identified in the LRA for the heat exchanger tubes in this system. The applicant is requested to provide the technical basis for excluding this aging effect on the heat exchangers.

Response:

The intended function of “exchange heat” was applied to the sample cooler tubes in error. The Sampling System sample coolers support the fire protection regulated event (10 CFR 50.48) and therefore are in-scope for license renewal under the 10 CFR 54.4(a)(3) criteria. Manual sampling of certain parameters to determine that an adequate cold shutdown margin has been achieved is credited in the fire protection safe shutdown analysis. The tube side of these coolers is in-scope for pressure boundary integrity, to ensure that a flow path to the sample sink is maintained. These coolers are not in-scope for the heat exchange intended function because the samples are taken when the fluid is relatively cool (approximately 200° F).

The intended function of “exchange heat” should not have been listed in LRA Tables 2.3.3.24 and 3.3.2-24 as an intended function for the sampling system heat exchanger tubes. Since the only intended function of the sample cooler tubes is “pressure boundary,” fouling is not an aging effect requiring management for license renewal.

ENCLOSURE 2

Joseph M. Farley Nuclear Plant Units 1 and 2

Application for License Renewal

Responses to March 23, 2004 Requests for Additional Information

(Partial)

RAI 2.0-2

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 2.3.3.3-1)

License renewal boundary drawings D-175043L (Unit 1) and D-205043L (Unit 2) do not appear to show any source of makeup water to the spent fuel pit (spent fuel pool) as being within the scope of license renewal. Section 9.1.3.3.2 of the FNP UFSAR states that the FNP spent fuel pool was designed in accordance with Regulatory Guide 1.13, which requires a diversity of makeup water sources to the spent fuel pool. Section 9.1.3.3.2 of the FNP UFSAR also credits the demineralized water system and the reactor makeup water system as being available to supply makeup water to the spent fuel pool, and Section 2.3.3.23 of the LRA states, "The license renewal intended function of the Reactor Makeup Water Storage System is to provide an assured seismic category I make-up source to ... the spent fuel pool."

Justify the exclusion of the piping and components connecting the demineralized water system and the reactor makeup water system to the spent fuel pool from the scope of license renewal and being subject to an AMR in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

Response:

The Reactor Makeup Water hose station in the Spent Fuel Pool area provides an assured Seismic Category 1 source of make-up water to the pool. This capability was added during the initial operating license review (refer to the SER for FNP, NUREG-75/034 dated 5/2/75 Section 1.6 item 19). This hose station and supply is in the scope of license renewal as described in LRA Section 2.3.3.23 and shown on the Reactor Makeup Water Storage System license renewal boundary drawings D175036L Sh1 and D205036L Sh 1.

Demineralized water provides for normal makeup (non-borated) to the spent fuel pool for evaporative losses and is not required for any safety-related or regulated event. This section of piping does not perform an intended function applicable to the criteria of 10 CFR 54.4(a)(1) or (a)(3). Portions of the demineralized water supply are in the scope of license renewal under the criteria of 10 CFR 54.4(a)(2) as described in LRA Section 2.3.3.16.

RAI 2.0-2 (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 2.3.3.19-1)

Note 5 of License renewal boundary drawing D - 506447L states that the LW&D system contains running traps and drain plugs that are non-safety-related but required to ensure that the penetration room filtration system will draw sufficient vacuum in response to a fuel handling accident and during recovery from certain DBAs. LRA Section 2.1.3.2 states that the running traps and floor drain plugs have been evaluated for aging effects. The LRA section lists floor drain plugs in Table 2.3.3.19. However, running traps are not included in Table 2.3.3.19. Justify the exclusion of running traps from being subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

Response:

A running trap is simply a "U" shaped arrangement of pipe and fittings designed to provide a water seal. Therefore running traps are included in Table 2.3.3.19 as "Piping," and have been evaluated for aging effects accordingly.

RAI 2.0-2 (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 2.3.3.19-2)

(a) LRA Section 2.3.3.19 states that the containment cooler condensate level monitoring subsystem is conservatively included in the scope of license renewal and is credited in the FNP CLB as a means to detect reactor coolant pressure boundary leakage as part of the LBB analyses. Section 5.2.7.1.1 of the UFSAR states that the condensate measuring system permits measurements of liquid runoff from the drain pans under each containment cooler fan unit. It consists of a vertical standpipe, valves, and standpipe level instrumentation installed in the drain piping of the reactor containment fan cooler unit. The staff is unable to find the vertical standpipes on license renewal boundary drawings D-175004L (Unit1) and D- 205004L (Unit 2). Confirm that these standpipes are within the scope of license renewal and subject to an AMR in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

Response:

The "vertical standpipes" described in the UFSAR are within the scope of license renewal and subject to an AMR in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively. The standpipes are vertically oriented piping and are part of the in-scope piping upstream of the level transmitters depicted on license renewal boundary drawings D-175004L (Unit 1) and D- 205004L (Unit 2). SNC has included the standpipes as part of the component type "piping" in Table 3.3.2-19 and has evaluated them for aging effects accordingly.

RAI 2.0-2 (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 2.3.3.19-2)

(b) License renewal boundary drawing D-205004L (Unit 2) shows two atmospheric vents at locations E11 and F8. The vent shown at location F8 is within the scope of license renewal. However, the vent shown at location E11 is not in scope of license renewal. Clarify the intended function of these vents and justify the exclusion of the latter vent from the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a).

Response:

The atmospheric vent for the containment cooler condensate level monitoring subsystem at location E11 on license renewal boundary drawing D205004L Sh. 1 (Unit 2) is in the scope of license renewal and should have been shown highlighted similar to the vent shown at location F8. This vent is correctly shown as in scope on the Unit 1 drawing (D175004L Sh. 1). These vent paths are part of the design for assuring proper level indication and monitoring of the condensate flow. The vent piping (including the vent at location E11 on drawing D205004L Sh. 1) was included LRA Table 2.3.3.19 as part of the component type "piping" with a component intended function of "pressure boundary" and subjected to an aging management review.

RAI 2.0-2 (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 2.3.3.19-2)

(c) Containment cooler condensate drains are shown on license renewal boundary drawings D-175004L (Unit 1) and D-205004L (Unit 2) at location E8, E9, E10 and E11. However, containment cooler condensate drains are not listed in LRA Table 2.3.3.19. Clarify if these drains are considered to be part of the component type, "piping," or some other component type listed in Table 3.3.2-19. If not, justify the exclusion of this component from being subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). Also, clarify if containment cooler condensate drains are supplied with traps or screens to prevent blockage in the standpipe. If so, justify the exclusion of containment cooler condensate drains from Table 2.3.3.19 as being subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

Response:

The drains for the containment cooler drain pans are composed of piping components (piping, fittings, etc.), are subject to an aging management review in accordance with the requirements of 10 CFR 54.21(a)(1), and are part of the component type "piping" in Table 3.3.2-19. There are no screens or traps provided to prevent blockage in the standpipe.

RAI 2.0-2 (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 2.3.3.19-2)

(d) A 3-inch atmospheric vent is shown on license renewal boundary drawing D-175004L (Unit 1) at location E8. Two 2-inch atmospheric vents are shown on license renewal boundary drawings D-175005L (Unit 1) and 205005L (Unit 2) at locations A11 and D11. Vents are passive long-lived components and are not listed in LRA Table 2.3.3.19. Clarify if vents are considered to be part of the component type, "piping," in Table 3.3.2-19. If not, justify the exclusion of this component from being subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

Response:

The atmospheric vents are shown on their respective license renewal boundary drawings as in the scope of license renewal. These vents are passive long-lived components that are comprised of piping that is open to the atmosphere. The vents are included in LRA Table 2.3.3.19 as part of the component type "piping."

RAI 2.0-2 (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 2.3.3.19-3)

The reactor coolant pump oil drip pan is shown on license renewal boundary drawing D-175005L (Unit 1) and D-205005L (Unit 2) at location C12 as within the scope of license renewal. The reactor coolant pump oil drip pan is a passive long-lived component. However, the reactor coolant pump oil drip pan is not listed in Table 2.3.3.19. Justify the exclusion of this component from LRA Table 2.3.3.19 as being subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

Response:

The reactor coolant pump oil drip pans are subject to aging management review, and are included in LRA Table 2.3.3.19 as part of the component type "tanks."

RAI 2.0-2 (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.

E. (D-RAI 2.3.3.19-5)

Section 2.3.3.19 of the LRA states that the compartment/room pressure sensors (assigned to the FNP liquid waste and drains system) that isolate the CVCS letdown line in the event of a CVCS letdown line rupture are addressed as part of the high-energy-line-break (HELB) detection system boundary. In addition, LRA Section 2.3.3.17 states that the HELB detection system includes compartment/room pressure and level sensors for the FNP liquid waste and drains system. However, the license renewal boundary drawings cited for the HELB detection system do not refer to the liquid waste and drains systems. Clarify why the liquid waste and drains systems are not listed on the license renewal boundary drawings for the HELB detection system.

Response:

The license renewal boundary drawings for the HELB detection system in LRA Section 2.3.3.17 include drawings D175039L sheet 1 (Unit 1) and D205039L sheet 1 (Unit 2). Table B on each of these boundary drawings lists eight instruments with "G21" Total Plant Numbering System (TPNS) designators. System G21 is the TPNS designator that corresponds to the LRA system "Liquid Waste and Drains" described in Section 2.3.3.19 of the LRA. The FNP TPNS designators were previously provided to the NRC Staff in response to RAI 2.2-3.

These HELB detection instruments are listed in a tabular format because there is no connected process piping. The system consists entirely of detection instruments and the associated sensing lines. The instruments are shown in the scope of license renewal on these boundary drawings and assigned to the HELB Detection System consistent with the descriptions provided in LRA Sections 2.3.3.17 and 2.3.3.19 and are included on the boundary drawings referenced in LRA section 2.3.3.17.

RAI 2.0-2 (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.

F. (D-RAI 2.3.4.4-2)

License renewal boundary drawing D-175016L, sheet 1, identified a symbol at location B10 as "Start-up Strainer Temporary." This symbol appears on license renewal boundary drawings D-175007L and D-205007L, sheet 1, at locations B4, E4, H4 for both drawings, and is shown as within the scope of license renewal. However, this component is not listed in LRA Table 2.3.4.4, which lists those components subject to an AMR. This component is passive and long-lived and should be subject to an AMR, in accordance with the requirements of 10 CFR 54.21. Justify the exclusion of these components from Table 2.3.4.4.

Response

The P&IDs as drawn indicate that the system is designed to provide for installation of temporary startup strainers. These strainers were removed after initial system startup testing and are no longer used. Pipe spool pieces are installed in these locations and are included as part of the component type "piping" in the LRA tables of components subject to an AMR.

RAI 2.0-2 (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.

G. (D-RAI 2.3.4.5-2)

For the staff to complete its review, please clarify whether the "auxiliary steam supply system" and the "auxiliary steam and condensate recovery system" are the same systems and, if not, describe how these two systems differ. Section 1.2.2 of the FNP UFSAR states that the "Auxiliary Steam Supply System is shared by Units 1 and 2". If these systems are the same, provide license renewal boundary drawings showing which portions of the system are shared between the two units and are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a).

Response:

The "Auxiliary Steam Supply System" listed in FNP UFSAR section 1.2.2 is the same as the "Auxiliary Steam and Condensate Recovery System" described in LRA section 2.3.4.5. [Please note, however, that the "Auxiliary Steam Supply System" listed in FNP UFSAR section 1.2.2 is not the same as the "Auxiliary Steam System" described in LRA section 2.3.4.1. The Auxiliary Steam System described in LRA section 2.3.4.1 is the supply lines from the main steam lines to the turbine-driven auxiliary feedwater pump turbine. These lines are shown on license renewal boundary drawings D175033L Sh. 2 (for Unit 1) and D205033L Sh. 2 (for Unit 2) and are described in UFSAR Sections 10.3.2.1 and 6.5.2.1.]

The shared components of the Auxiliary Steam and Condensate Recovery System are the auxiliary steam generator, steam supply piping connecting the auxiliary steam generator to the Unit 1 auxiliary steam distribution piping, and condensate return piping from each unit to the auxiliary steam generator. The auxiliary steam generator is no longer operational as stated in LRA section 2.3.4.5. All shared components are located in the Turbine Buildings, and are not in scope for License Renewal because they do not perform any intended function as described in 10 CFR 54.4(a).

RAI 2.0-2 (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.

H. (D-RAI 3.3.2.13-1) Correction to numbering reflected in March 23, 2004 RAI letter

LRA Table 3.3.2-13 identifies spray shields as a component type, as does LRA Section 2.3.3.13. Neither the section text nor the license renewal boundary drawings identify where or how these components are used. Describe these components and identify the locations where these components are used at FNP.

Response

Schematic representations of spray shields are identified in the "Legend" section of boundary drawings containing these components. An example of a spray shield on a boundary drawing is found on D-170871L sheet 1. The schematic representation is shown under "Legend" and a spray shield is depicted in the body of the drawing at coordinate F-2. Thus, spray shields are depicted on the boundary drawings and highlighted if they are in the scope of license renewal. Spray shields are used to limit sprinkler flow to specific targets in the event of suppression system activation. These components are constructed of metal sheeting.

RAI 2.3.3.4-1

In Section 2.3.3.4, the applicant provides a brief description of the overhead heavy and refueling load handling system. This section of the LRA identifies the containment polar crane, the reactor cavity manipulator crane, the spent fuel pool bridge crane, the spent fuel cask crane, and the special tools and adapters used for lifting and handling refueling loads as being part of the overhead heavy and refueling load handling system. However, the LRA does not identify which of these cranes have components subject to an AMR, nor does LRA table 2.3.3.4 identify any of the special tools and adapters used for lifting and handling of refueling loads as being subject to an AMR. Identify the specific cranes that contain components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1), and justify the exclusion of the special tools and adapters used for lifting and handling refueling loads from an AMR.

Response:

The containment polar crane, the reactor cavity manipulator crane, the spent fuel pool bridge crane, and the spent fuel cask crane are in the scope of license renewal and contain components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The special tools and adapters used for lifting and handling the reactor vessel head, internals, and fuel assembly inserts are in the scope of license renewal but are not subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). Special tools and adapters include the head lifting rig, rod control cluster handling tool, the thimble plug handling tool, burnable poison rod assembly tool, and the spent fuel handling tool. The scoping process determined these devices perform their intended function(s) with moving parts and/or change in configuration. Such devices are considered active components and therefore not subject to an AMR. FNP performs inspections and/or tests prior to initial use (e.g., each refueling outage).

Additional discussion and clarification of the scoping method and results for load handling systems (cranes, hoists and monorails) is provided in responses to RAIs 2.3.3.4-2 (in this enclosure) and 2.4-3 (see SNC letter NL-04-0383 to the NRC dated March 12, 2004).

RAI 2.3.3.4-2

Several structures typically contain cranes or hoists located above or near safety related equipment (for example, the intake structure and the diesel generator building). Describe how areas containing cranes or hoists near safety-related equipment were evaluated to identify cranes or hoists subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1), and identify where those components are identified in the LRA.

Response:

Cranes and hoists were evaluated by the civil discipline for the FNP LRA. The approach used to scope civil/structural features inside structures housing safety-related SSCs addresses the potential for interaction of civil/structural non safety-related SSCs with safety-related SSCs that could result in the failure of a safety-related SSC to perform its function. This is described in Section 2.1.3.2 of the LRA. As indicated in the LRA, a spaces approach was used to place all civil/structural components in a structure housing safety-related SSCs in scope for license renewal. Therefore, all cranes and hoists located above or near safety-related equipment were put into scope.

Cranes and hoists components are included in the LRA based on the following approach. The cranes associated with overhead heavy and fuel-related load handling were grouped together in LRA Section 2.3.3.4 (to align with the NUREG-1801 grouping) with the components subject to an AMR identified in Table 2.3.3.4. All other cranes and hoists were included in scope as part of the overall evaluation of its structure in Section 2.4. The components subject to an AMR are included in the component type "Steel Components: All Structural Steel" listed in the Components Subject to an AMR table for the associated structure.

RAI 2.3.3.13-1

The license renewal boundary drawings in LRA Section 2.3.3.13 identify those portions of fire protection systems within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a). The following questions relate to these drawings:

A. License renewal boundary drawing D-170384L, sheet 2, identifies low pressure carbon dioxide systems on the 155'0" level of the Unit 1 turbine building as not being within the scope of license renewal. The system located between E-9 and G-9 on the drawing is not identified. License renewal boundary drawing D-200152L, sheet 1, identifies low pressure carbon dioxide systems in the Unit 2 turbine building and excluded the load centers and 4160 V switchgear from scope. Identify the unlabeled system in Unit 1 and justify the exclusion of these systems in Unit 1 and 2 from the scope of license renewal.

Response:

The only in-scope carbon dioxide (CO2) SSCs in the Turbine Building are those associated with the low pressure bulk CO2 storage and supply system that supplies CO2 to both Unit 1 and Unit 2 Auxiliary Building CO2 systems. The auxiliary building CO2 fire suppression equipment is relied upon to protect safety-related SSCs and ensure safe shutdown in the event of a fire as part of FNP's compliance with 10 CFR 50.48.

Drawing D-170384L sheet 2 is included as a boundary drawing because a portion of the in-scope boundary from another drawing continues on this drawing up to and including the isolating device. The Unit 1 Turbine Building low pressure CO2 SSCs on the 155' elevation shown on the drawing are not in license renewal scope (i.e., not highlighted) because the fire suppression capability is not relied upon for compliance with 10 CFR 50.48. The 4 KV switchgear buses and 600 volt load center buses that are being fire protected by the CO2 SSCs on the 155'0' elevation are not safety related and not relied upon for safe shutdown. These Unit 1 Turbine Building low pressure CO2 suppression systems on the 155'0" elevation exist for commercial property protection. The system located between E-9 and G-9 on this drawing is the CO2 suppression system for the non safety-related 4 KV switchgear bus 1E (system 1T-14), and as described above, is not in the scope of license renewal. The descriptive label for this equipment was inadvertently left off the license renewal drawing.

The CO2 SSCs for the load center buses and 4 KV switchgear buses in the Unit 2 Turbine Building (D-200152L sheet 1) are not in the scope of license renewal because they are not relied upon for compliance with 10 CFR 50.48 (same explanation as above for Unit 1). This drawing is included as a boundary drawing because a portion of the in-scope boundary from another drawing continues on this drawing up to and including the isolating device(s).

RAI 2.3.3.13-1 (Continued)

The license renewal boundary drawings in LRA Section 2.3.3.13 identify those portions of fire protection systems within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a). The following questions relate to these drawings:

B. License renewal boundary drawing D-170385L, Sheet 1, identifies Unit 1 high pressure carbon dioxide systems in the river water switchgear as not within the scope of license renewal. Justify the exclusion of these systems from the scope of license renewal.

Response:

Loss of the River Water System is discussed in UFSAR Section 9.2.1.2.3.1 which states "The station cooling water system is designed such that safe shutdown of the plant is not dependent on the river water system as a cooling water source" and "The storage pond alone serves as the ultimate heat sink for the plant." The River Water System is located remote from the plant's safety-related structures (over 2000 feet from the Auxiliary Buildings and from the pond) and houses the river water pumps and related equipment, none of which are required for safe shutdown (including in the event of a fire) or to mitigate any accident. The portions of the River Water System within the scope of License Renewal (i.e., the Service Water pond level instruments) described in LRA Section 2.3.3.5 are located at the (Service Water) pond and not in proximity of the River Water Structure. CO2 systems located in the River Water Intake Structure for suppressing a fire in the switchgear are not in the scope of license renewal because the equipment is not relied upon for compliance with 10 CFR 50.48.

RAI 2.3.3.13-1 (Continued)

The license renewal boundary drawings in LRA Section 2.3.3.13 identify those portions of fire protection systems within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a). The following questions relate to these drawings:

C. License renewal boundary drawing D-170386L, sheet 1, identifies the Unit 1 halon fire protection systems, and D-205021L, sheet 1, identifies the Unit 2 halon fire protection systems. Both drawings include the fire protection system in the communications room and excluded the systems in the computer room and control system cabinet room. Justify the exclusion of the fire protection systems in the computer room and control system cabinet room from the scope of license renewal.

Response:

The halon fire protection systems for the control system cabinet rooms for Unit 1 and Unit 2 are located in rooms 235 and 2235, respectively. The halon fire protection systems for the computer rooms for Unit 1 and Unit 2 are located in rooms 201 and 2201, respectively.

From UFSAR Section 9B, Attachment A, Fire Area Hazard Analysis for the control system cabinet rooms for Unit 1 and Unit 2 (fire areas 1-23 and 2-23, respectively),

> "A total-flooding halon system is provided which is activated by detectors; however, the water hose station installed in room 234 [Unit 1] 2234 [Unit 2] outside of room 235 [Unit 1] 2235 [Unit 2] provides for fire suppression capabilities to comply with BTP APCSB 9.5-1."

From UFSAR Section 9B, Attachment A, Fire Area Hazard Analysis for the computer rooms for Unit 1 and Unit 2 (fire areas 1-14 and 2-14, respectively),

> "An automatic total-flooding halon system is provided, however, the CO2 hose reel located in room 210 [Unit 1] 2210 [Unit 2] provides for fire suppression capabilities to comply with BTP APCSB 9.5-1."

It is noted that the CO2 hose reels are located in rooms exterior to but in proximity of the computer rooms.

Therefore, the halon fire protection systems for the control system cabinet rooms and computer rooms for both FNP units remain in place but are not relied upon for 10 CFR 50.48 compliance, and are not in the scope of license renewal.

RAI 2.3.3.13-1 (Continued)

The license renewal boundary drawings in LRA Section 2.3.3.13 identify those portions of fire protection systems within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a). The following questions relate to these drawings:

D. License renewal boundary drawing D-508526L, Sheet 1, identifies the fuel oil systems for the diesel engine fire pumps. The drawing shows the license renewal boundary at the flexible supply and return line connection. Excluded from scope are the flexible fuel lines, housings for the fuel filters, and fuel pumps. Justify the exclusion of these components from the scope of license renewal.

Response:

The fuel oil systems for the diesel engine fire pumps are identified on license renewal boundary drawing D-508562L, Sheet 1. These components, which are located on the fire pump diesel skid, are in-scope and treated as an integral part of the diesel engine active assembly. These components should have been highlighted on the drawing indicating that they are in-scope.

RAI 2.3.3.13-2

The FNP UFSAR identifies the cable fire barrier, such as Kaowool, needed to meet the requirements of 10 CFR 50.48, Appendix R. No reference to these fire barriers is made in LRA Section 2.3.3.13 or Section 2.4. Identify where these barriers are addressed in the scoping and screening process. Confirm that they are subject to an AMR, or justify their exclusion from the scope of license renewal and from being subject to an AMR in accordance with the requirements of 10 CFR 54.4(a)(3) and 10 CFR 54.21(a)(1), respectively.

Response:

Cable fire barriers, such as Kaowool and Maranite, were addressed in the scoping for fire barriers credited in the CLB. These barrier materials were subjected to a commodity-based aging management review and determined not to have aging effects requiring management. Kaowool is presently utilized as a fire barrier material in the Auxiliary Building and Service Water Intake Structure only. Maranite is utilized in the Auxiliary Building, Diesel Generator Building and Service Water Intake Structure.

Fire wraps and fire stops were inadvertently omitted as a component type from LRA Tables 2.4.2.1, 2.4.2.2 and 2.4.2.5. These tables should have included the following:

Component Type	Intended Function
Cable Fire Wrap and Fire Stops	Fire Barrier

Correspondingly, the aging management review summary Tables 3.5.2-2, 3.5.2-3 and 3.5.2-6 should have included the following:

Component Type *GALL Reference*	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
Cable Fire Wrap and Fire Stops	Fire Barrier	Kaowool (Kaolin fiber insulation) Maranite (Calcium Silicate Board)	Inside	None	None Required	N/A	N/A	F

RAI 2.3.3.13-3

According to the FNP UFSAR, in certain area of the plant, such as the cable spreading room, structural steel members are provided with sprayed-on fire resistive materials. These materials are not discussed in either the scoping and screening or the aging management sections of the LRA. Confirm that the fire resistive coatings for structural steel members are in scope and subject to an AMR in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively, or justify their exclusion.

Response:

Sprayed-on or trowelled-on fire resistive materials provided on in-scope structural steel members are in scope for license renewal and are subject to an AMR in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). Fire resistive structural steel protection is used in the Auxiliary Building (Cable Spreading Room) as well as on doors at the Diesel Generator building entrance to the cable tunnels. These coatings should have been identified in LRA Table 2.4.2.1 as follows:

Component Type	Intended Function
Structural steel & doors with sprayed-on or trowelled-on fire resistive material	Structural / support Fire Barrier Shelter / protection

Correspondingly, the aging management review summary Table 3.5.2-2 should have included the following:

Component Type *GALL Reference*	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
Structural steel & doors with sprayed-on or trowelled-on fire resistive material	Structural / support Fire Barrier Shelter / protection	Steel	Inside	Loss of material	Structural Monitoring Program			F, 48

Plant specific note 48:
The sprayed-on or trowelled-on fire resistive material has no aging effects requiring aging management. In the course of inspecting the underlying steel surfaces by the Structural Monitoring Program, any degradation in the sprayed-on or trowelled-on coating would however be identified and remedied in accordance with the Corrective Action program described in section B.1.4.1 of the LRA.

RAI 2.3.3.21-1

The potable and sanitary water system is non-safety-related, but is in the scope of license renewal due to the potential for spatial interaction with safety-related components according to 10 CFR 54.4(a)(2). LRA Table 2.3.3.21 provides a list of the components that are subject to an AMR. LRA Section 2.3.3.21 does not provide or reference any license renewal boundary drawings associated with the potable and sanitary water system. Section 9.2.4.2 of the UFSAR states that the P&ID for the potable and sanitary water system is shown in drawing D-170127. However, this drawing has not been provided to the staff for review.

For the staff to complete its review, provide a description or boundary drawing which identifies the components of the potable and sanitary water system considered to be within the scope of license renewal and subject to an AMR in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1), respectively.

Response:

The Potable and Sanitary Water (P&SW) LRA System includes the Sanitary Water System and the Plant Hot Water Heating System. The Sanitary Water System supplies domestic water for use throughout the plant. The Plant Hot Water Heating System carries water from the plant heating system heat exchanger to air handling heating coils located throughout the Auxiliary Building. The Plant Hot Water Heating System is in scope for high energy line considerations as described in UFSAR Section 3K.4.2.4. Other portions of the P&SW System brought into scope for license renewal per criterion 10CFR54.4(a)(2) for spatial interaction are identified on license renewal boundary drawing D506447L (Sheet 1) by listing the room numbers that include the in-scope SSCs.

LRA Table 2.3.3.21 provides a listing of the component types that are subject to an AMR and Table 3.3.2-21 identifies the applicable material and environment combinations for these component types and the aging management review results. The in-scope portion of the Plant Hot Water Heating System includes closure bolting, piping components (piping, fittings, etc.), valves, heat exchangers, strainers, and tanks. The in-scope portion of the Sanitary Water System includes closure bolting, piping components (piping, fittings, etc.), valves, and tanks.

RAI 2.3.3.22-1

Section 2.3.3.22 of the LRA states that "the process and effluent radiological monitoring portion of the radiation monitoring system is used to monitor process and effluent streams during normal operations and postulated accidents to provide indication and record releases of radioactive materials generated and to initiate automatic system responses. The in-scope portions are addressed as part of the LRA system that includes the process or effluent being monitored." The in-process radiation monitoring elements (RE-0020A/B and RE-0017A/B) shown on the license renewal boundary drawings for the CCW and OCCW systems are installed in-line and therefore serve a pressure boundary intended function. However, these components are not listed in the LRA tables as being subject to an AMR. LRA Section 2.3.3.22 does not provide a list of the systems that contain the process or effluent being monitored, nor reference any boundary drawings associated with the radiation monitoring system. Therefore, the staff cannot confirm that the SSCs meeting the requirements of 10 CFR 54.4(a) are included within the scope of license renewal. Provide a list of the LRA systems which include process or effluent being monitored by components of the radiation monitoring system.

Response:

Radiation monitors that are installed in-line on an in-scope portion of a process system serve a pressure boundary intended function and therefore are in the scope of license renewal. The intent of the description in Section 2.3.3.22 of the LRA was to clarify that for this situation, SNC included the radiation monitor in the scoping results for the mechanical system being monitored. The monitors are shown in the in-scope boundary on the process system's license renewal boundary drawing (there are no radiation monitoring system license renewal boundary drawings). The intent of the last paragraph of the *System Description* for Section 2.3.3.22 was to clarify the function of the radiation monitors are instrumentation and addressed by SNC in the scoping and screening results in Section 2.5, "Electrical and Instrumentation and Controls Systems." The radiation sensing instrumentation addressed in the electrical scoping and screening process performs its function utilizing a change in property as defined by 10 CFR 54.21 (a)(1), and therefore is active and not subject to an aging management review.

In some applications, the in-line radiation monitors connect to the process system using piping/ductwork fittings (e.g., in-line piping tee, etc.) that were provided as part of the monitor. For this situation, the items were treated the same as piping or ductwork fittings and included in the component type "piping" for piping applications, and in the component type "ducts and fittings" for ventilation applications. These components were subject to an AMR accordingly.

The following table has been developed in response to the staff's request to provide a listing of the LRA systems which include process or effluent being monitored by components of the radiation monitoring system. This table provides a list of those radiation monitors that are part of a mechanical LRA system's in-scope pressure boundary.

Radiation Monitors That Are Part of A Mechanical LRA System's In-Scope Pressure Boundary

Radiation Monitor	Description	LRA System	LRA Section	License Renewal Boundary Drawing(s)
R-10	Penetration Room Filtration Particulate Monitor	A&RAV	2.3.3.10	D-175045L D-205045L
R-11	Containment Air Particulate Process Monitor	PCHVAC	2.3.3.11	D-175010L Sh. 2 D-205010L Sh. 2 (See Note 1)
R-12	Containment Radioactive Gas Monitor	PCHVAC	2.3.3.11	D-175010L Sh. 2 D-205010L Sh. 2 (See Note 1)
R-25A, B	Spent Fuel Pool Ventilation Noble Gas Monitor	A&RAV	2.3.3.10	D-175045L D-205045L
R-67	Containment Post Accident Particulate/Iodine/Noble Gas Grab Sampler	PCHVAC	2.3.3.11	D-175010L Sh. 2 D-205010L Sh. 2
R-17A, B	Component Cooling Water Pump Suction Monitor	CCW	2.3.3.6	D-175002L Sh. 1 D-205002L Sh. 1
R-35A, B	Control Room Makeup Air Inlet Noble Gas Monitor	CRAV	2.3.3.9	D-205012L Sh. 1
R-20A, B	Containment Cooler Service Water Outlet Monitor	OCCW	2.3.3.5	D-175003L Sh. 1 D-205003L Sh. 1
R-24A, B	Containment Purge Noble Gas Monitor	PCHVAC	2.3.3.11	D-175010L Sh. 2 D-205010L Sh. 2
R-29B	Plant Vent Stack Particulate/Iodine/Noble Gas Monitor	A&RAV	2.3.3.10	D-175045L D-205045L

Note 1:
Included in the above table are containment air particulate (R-11) and radioactive gas (R-12) monitors that provide reactor coolant leakage detection as stated in UFSAR Section 17.3.5. These monitors were inadvertently not shown in-scope on the PCHVAC/Containment Isolation boundary drawings D-175010L (Sheet 2) and D-205010L (Sheet 2). On these drawings, the components downstream of the outboard containment isolation valves HV-3657 and HV-3658 up to including R-11 and R-12 and including the in-line piping portion of the containment radiation monitor (R-67) should have been shown in-scope for license renewal. and subject to an AMR pursuant to 10 CFR 54.4(a) and 10 CFR 54.21(a). The Containment Isolation system component types in Table 2.3.2.2 already include the component types subject to an AMR and there is no impact to the aging management review presented in Table 3.2.2-2.

RAI 2.3.4.4-1

UFSAR Section 6.5.2.2.2 states that "Turbine bearings are lubricated by a forced feed lube oil system driven from the turbine shaft. Lube oil cooling water is supplied from the first stage of the auxiliary feedwater pump discharge and returned to the pump via the pump balancing line. This arrangement ensures a supply of cooled lube oil whenever the turbine is operating." Since the AFW pump turbine drive must be operable for the AFW system to perform its intended function, the staff considers the turbine lube oil subsystem to be within the scope of license renewal.

LRA Table 2.3.4.4 lists the components of the AFW system that are subject to an AMR. Some items included are: Filters (casing), Oil Cooler (shell), Oil Cooler (channel head), Oil Cooler (tube sheet), Oil Cooler (tubes). These components comprise part of the turbine lube oil subsystem. The AFW pump and its turbine drive are shown on license renewal boundary drawings D-175007L and D-205007L (location H5 on both drawings) and also on D-175033L and D-205033L (Sheet 2, location E3 on both drawings). However, the turbine lube oil subsystem and its components are not shown on these drawings.

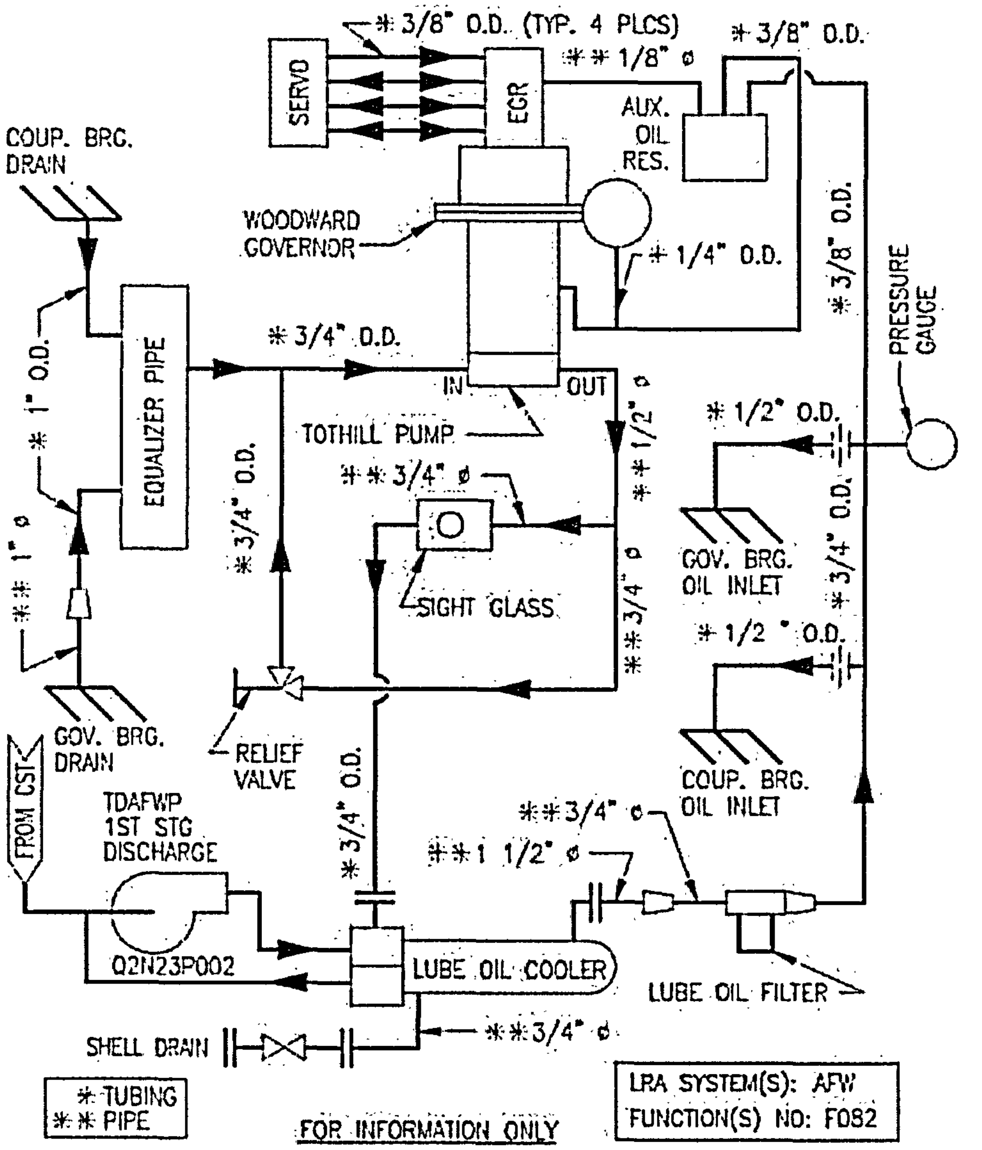
Identify which cooling water system is used to cool the lube oil in the heat exchanger. Confirm that all components of the turbine lube oil subsystem (AFW system) are within the scope of license renewal and subject to an AMR in accordance with the requirements of 10 CFR 54.4(a) and 54.21(a)(1), respectively; or provide drawings which show the turbine lube oil subsystem and all of its components, and identify those components considered to be within the scope of license renewal and subject to an AMR.

Response:

As stated in the UFSAR, "Lube oil cooling water is supplied from the first stage of the auxiliary feedwater pump discharge and returned to the pump suction via the pump balancing line." Therefore, the cooling water supply used to cool the lube oil heat exchanger for the turbine-driven Auxiliary Feedwater (AFW) pump is supplied directly from the AFW System. As stated in Section 2.3.4.4 of the LRA, the AFW System water source is the Condensate Storage Tank.

In response to the staff's request, Figure 2.3.4.4-1, "Turbine Driven AFW Pump Turbine Lube Oil Piping Schematic", was developed to identify the components of this subsystem and to present SNC's scoping results in accordance with the requirements of 10 CFR 54.4(a).

TURBINE DRIVEN AFW PUMP
LUBE OIL PIPING SCHEMATIC
(FROM U-277859: TDAWF PUMP TURBINE MANUAL)



The component types subject to an aging management review (AMR) in accordance with 10 CFR 54.21(a) for the Turbine Driven AFW Pump Turbine Lube Oil Subsystem are identified in the following table.

Table 2.3.4.4-1 Turbine Driven AFW Pump Turbine Lube Oil Subsystem Component Types Subject to Aging Management Review and Their Intended Functions

Component Type	Intended Function
Closure Bolting	Pressure Boundary
Filters (casing)	Pressure Boundary
Flow Orifice/Element	Flow Restriction Pressure Boundary
Oil Cooler (shell)	Pressure Boundary
Oil Cooler (channel head)	Pressure Boundary
Oil Cooler (tube sheet)	Pressure Boundary
Oil Cooler (tubes)	Exchange Heat Pressure Boundary
Piping	Pressure Boundary
Pump Casings	Pressure Boundary
Sight Glasses	Pressure Boundary
Tanks (Auxiliary Oil Reservoir)	Pressure Boundary
Valve Bodies	Pressure Boundary

Three of the component types listed - "Flow Orifice/Element", "Sight Glasses", and "Tanks" - were not included in the LRA as part of the Turbine Driven AFW Pump Turbine Lube Oil Subsystem of the AFW System. The "Sight Glasses", and "Tanks" component types and associated intended functions should have been included in Table 2.3.4.4 of the LRA (the "Flow Orifice/Element" component type is already in the table). Aging management reviews for these components were performed.

The AFW System aging management review summary in Table 3.4.2-4 of the LRA should have included the following:

Component Type *GALL Reference*	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
Flow Orifice/Element	Flow Restriction Pressure Boundary	Stainless Steel	Lube Oil	None	None Required	N/A	N/A	J
			Inside	None	None Required	N/A	N/A	J
Sight Glasses	Pressure Boundary	Glass	Lube Oil	None	None Required	N/A	N/A	J
			Inside	None	None Required	N/A	N/A	J
Tanks (Auxiliary Oil Reservoir)	Pressure Boundary	Carbon Steel	Lube Oil	None	None Required	N/A	N/A	J
			Inside	Loss of material	External Surfaces Monitoring Program	VIII.H.1-b	3.4.1-5	A

ENCLOSURE 3

Joseph M. Farley Nuclear Plant Units 1 and 2

Application for License Renewal

Revised Responses to RAI 3.4-1 and RAI 3.4-5

RAI 3.4-1

For various stainless steel components in LRA Table 3.4.2-x

(a) Cracking is identified as the aging effect for various stainless steel components in steam or treated water environments. The applicant credits the Water Chemistry Control Program to manage this aging effect. Since stainless steels are susceptible to cracking in these types of environments, the applicant is requested to justify why the Water Chemistry Control Program without an inspection program to verify that cracking is not occurring is adequate to manage this aging effect, or to provide an inspection program.

(b) Loss of material is identified as the aging effect for various stainless steel components in treated water environments. The applicant credits the Water Chemistry Control Program to manage this aging effect. Stainless steels are susceptible to loss of material in this type of environment and the GALL report recommends that, for loss of material due to pitting and crevice corrosion, the effectiveness of the Water Chemistry Control Program should be verified to ensure that significant degradation is not occurring. The applicant is requested to perform a one-time inspection to verify the effectiveness of the Water Chemistry Control Program or to provide justification for not performing a one-time inspection.

Response

The FNP Water Chemistry Control Program provides for control of chemistry parameters associated with corrosion of stainless steel components in steam and power conversion systems. This program is consistent with the guidance contained in EPRI TR-102134, "Secondary Water Chemistry Guidelines." In accordance with EPRI TR-102134, chloride and sulfate concentrations are maintained in the low ppb range. Additionally, dissolved oxygen concentrations are maintained in the low ppb range through the addition of oxygen scavengers. Under these conditions, corrosion of austenitic stainless steel components is unlikely.

The FNP operating experience review performed for development of the FNP license renewal application did not identify any failures of stainless steel components in steam and power conversions systems due to cracking or loss of material. The operating experience review also confirmed the FNP Water Chemistry Control Program has effectively monitored and maintained chemistry parameters within specified target values (that are below the control (limit) values). Minor instances of chemistry parameters outside of specified limits were promptly restored within acceptable limits. This site specific operating experience confirms that the Water Chemistry Control Program without an inspection program is adequate to manage this aging effect without performing a one-time inspection.

Furthermore, comparison to previous applicants indicates that the FNP aging management strategy for stainless steel components exposed to a steam or treated water environment is similar to the strategy previously approved by the NRC staff.

RAI 3.4-5

LRA Table 3.4.1-4 states that loss of material was determined not to be an aging effect requiring management for the auxiliary feedwater (AFW) system turbine oil cooling system. Table 3.4.2-4 identifies no aging effects requiring management for carbon and stainless AFW components in an oil environment. For AFW oil cooler tubes, Table 3.4.2-4 only identifies fouling as an aging effect requiring management. The GALL report recommends a plant-specific aging management program for loss of material due to general (carbon steel only), pitting, and crevice corrosion and MIC in carbon and stainless steel components exposed to lubricating oil that may be contaminated with water. The staff considers a periodic inspection program appropriate to manage these aging effects. Industry operating experience indicates that moisture in oil has caused degradation in these types of components. For the filters, flow orifice/element, oil cooler shell, oil cooler channel head, oil cooler tube sheet, oil cooler tubes, piping, pump casings, and valve bodies in the AFW system exposed to an oil environment, the applicant is requested to provide aging management for loss of material due to general (carbon steel only), pitting, and crevice corrosion and MIC, or to provide justification for not managing this aging effect.

Response

The SNC position as stated in LRA Section 3.4.2.2.5 is that lubricating oil systems at FNP are not assumed to be contaminated with water. Lubricating oil systems are assumed to be free of water contamination as their initial condition. Lubricating oil systems are typically closed systems that have little potential for ingress of contaminants unless a component failure occurs. License Renewal does not assume component failures as a means to establish the conditions necessary for aging to occur. For example, tube failures in lubricating oil coolers are not assumed because the cooling water side of the tubes is age-managed. Therefore, water contamination of lubricating oil is event driven, and would be addressed by corrective maintenance. For License Renewal purposes, lubricating oil is therefore assumed to be free of water contamination.

Although they are not credited for aging management, other site activities provide added assurance that lube oil is not contaminated with water. Oil levels are visually checked every shift for proper level and for visual evidence of contamination (milky appearance of oil or visible oil/water boundary). The oil is sampled every three months and is changed based on the results of the sample analysis. Oil levels and condition are also checked during quarterly pump surveillance testing.

The EPRI Mechanical Tools indicate that significant corrosion is only expected where water can settle or pool. However, since water contamination is not expected, lubricating oil systems are not susceptible to loss of material due to general corrosion, pitting, crevice corrosion or MIC. FNP operating experience supports this conclusion.

SNC has concluded that the aging management strategy is consistent with the strategy of prior applicants that have previously been accepted by the NRC Staff.