Monitoring Program in SER Section 3.0.3.2.6. Based on its review, the staff finds the proposed program acceptable for managing cracking due to fatigue in stainless steel piping and piping components exposed to steam. The ASME Boiler & Pressure Vessel Code, Section III gives curves for fatigue of stainless steel and the Fatigue Monitoring Program is a conservative way to manage this aging effect.

In LRA Table 3.4.2-1-IP2, the applicant applied Note F and identified "cracking–fatigue" as the aging effect for stainless steel strainers exposed to steam (external). The applicant has credited the Fatigue Monitoring Program with managing this aging effect. The staff documents its review and evaluation of the proposed Fatigue Monitoring Program in SER Section 3.0.3.2.6. Based on its review, the staff finds the proposed program acceptable for managing cracking due to fatigue in stainless steel piping and piping components such as strainers exposed to steam. The ASME Boiler & Pressure Vessel Code, Section III gives curves for fatigue of stainless steel and the Fatigue Monitoring Program is a conservative way to manage this aging effect.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of combinations of material, environment, AERM, and AMP not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed, so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4A.2.3.2 Main Feedwater System—Summary of Aging Management Review—
LRA Table 3.4.2-2-IP2

The staff reviewed LRA Table 3.4.2-2-IP2, which summarizes the results of AMR evaluations for the main feedwater system component groups.

In LRA Table 3.4.2-2-IP2, the applicant used Note I and identified no aging effect for the carbon steel bolting, piping, and valve bodies externally exposed to the plant indoor air environment. Note I for these AMR lines is further supplemented by the plant-specific Note 401, which states that the applicable components are not subject to moisture condensation because they remain at high temperatures during normal plant operation. The components have a similar material and environment as Item SP-1 in the GALL Report, which is applicable to the steel piping, piping components, and piping elements in an external environment of indoor air and does not require an AERM or AMP. On the basis that the LRA components are similar to other GALL Report items for the material and environment (e.g., GALL Report, Volume 2, Table V.F, Line Item V.F-16, whereby the AERM is listed as "none," the AMP is listed as "none," and no further evaluation is required), the staff finds that the effect of plant indoor air on steel components at elevated temperatures will not result in aging that will be of concern during the period of extended operation.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of combinations of material, environment, AERM, and AMP not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed, so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4A.2.3.3 Auxiliary Feedwater System—Summary of Aging Management Review—
LRA Table 3.4.2-3-IP2

The staff reviewed LRA Table 3.4.2-3-IP2, which summarizes the results of AMR evaluations for the AFW system component groups.

In LRA Table 3.4.2-3-IP2, the applicant applied Note F and identified "cracking–fatigue" as the aging effect for stainless steel strainers exposed to steam (external). The applicant has credited the Fatigue Monitoring Program with managing this aging effect. The staff reviewed and evaluated the proposed Fatigue Monitoring Program and documents its evaluation in SER Section 3.0.3.2.6. Based on its review, the staff finds the proposed program acceptable for managing cracking due to fatigue in stainless steel piping and piping components such as strainers exposed to steam. The ASME Boiler & Pressure Vessel Code, Section III gives curves for fatigue of stainless steel and the Fatigue Monitoring Program is a conservative way to manage this aging effect.

In LRA Table 3.4.2-3-IP2, the applicant proposed using the External Surfaces Monitoring Program to manage the loss of material in stainless steel piping, tubing, and valve bodies exposed to an external environment of outdoor air. The applicant applied Note G to indicate that the environment for these components and material is not included in the GALL Report. The staff finds that the applicant's External Surfaces Monitoring Program includes periodic visual inspections of external surfaces during the system engineers' walkdowns of the systems. The staff evaluates the External Surfaces Monitoring Program in SER Section 3.0.3.2.5. The staff finds that the aging effect of the loss of material in stainless steel piping tubing and valve bodies exposed to an external environment of outdoor air will be adequately managed by using the External Surfaces Monitoring Program.

In LRA Table 3.4.2-3-IP2, the applicant proposed using the One-Time Inspection Program to manage the loss of material in stainless steel tubing and valve bodies exposed to a treated water (internal) environment. The applicant applied Note G and plant-specific Note 407 to indicate that the environment for these components and material is not included in the GALL Report. The staff finds that the applicant's One-Time Inspection Program will use inspections to detect whether these components are incurring a loss of material. The program uses both visual and NDE techniques for inspection. The program includes a provision that any unacceptable results or findings will be evaluated in accordance with the site corrective action process to determine the need for subsequent (including periodic) inspections. The staff evaluates the External Surfaces Monitoring Program in SER Section 3.0.3.1.9. Based on the above, the staff finds that the aging effect of the loss of material in these components will be adequately managed by using the One-Time Inspection Program.

In LRA Table 3.4.2-3-IP2, the applicant applied Note G and identified the loss of material as the aging effect for carbon steel piping exposed to treated water (internal) and proposed the Periodic Surveillance and Preventive Maintenance Program to manage the effects of aging. The staff's review of the Periodic Surveillance and Preventive Maintenance Program is documented in SER Section 3.0.3.3.7. In addition to Note G, the applicant applies Note 407 to this line item. Note 407 states, "This treated water environment includes water that has been treated but is not maintained by a chemistry control program, such as water from the city water system. There is no environment in NUREG-1801 that will support a useful comparison for this line." The GALL Report states that, "Raw water may contain contaminates, including oil and

boric acid, depending on the location, as well as originally treated water that is not monitored by a chemistry program." Therefore, it is the staff's opinion that this environment should be classified as raw water according to the GALL Report definition. The applicant has credited the Periodic Surveillance and Preventive Maintenance Program with managing the aging effect. This program includes activities to monitor components to detect degradation and monitor parameters such as wall thickness and surface condition. The program uses both visual and NDE techniques to perform inspections. Based on its review, the staff finds the proposed program acceptable for managing the loss of material in steel piping and piping components such as valve bodies.

In LRA Table 3.4.2-3-IP2, the applicant proposed using the Bolting Integrity Program to manage the loss of material in stainless steel bolting exposed to the outdoor air (external) environment. The applicant applied Note G to indicate that the environment for this component and material is not included in the GALL Report. The staff evaluates the Bolting Integrity Program in Section 3.0.3.2.2. This program is also recommended in Table 4, Item 22, of the GALL Report to manage the loss of material due to general, pitting, and crevice corrosion in steel bolting exposed to outdoor air (external). Based on the above, the staff finds that the aging effect of the loss of material in these components will be adequately managed by using the Bolting Integrity Program.

In LRA Table 3.4.2-3-IP2, the applicant applied Note G and plant-specific Note 402 to carbon steel piping externally exposed to condensation with an aging effect of loss of material. Note 402 states, "[t]his environment is inside the condensate storage tank [CST]. The tank vapor space is nitrogen blanketed but the environment is conservatively assumed to be condensation." The applicant proposed the Water Chemistry Control – Primary and Secondary Program to manage the effects of aging. The staff's review of Water Chemistry Control – Primary and Secondary Program is documented in SER Section 3.0.3.2.17. In Table VIII.H, Line Item VIII.H-10 of the GALL Report, it recommends the use of the External Surfaces Monitoring Program to manage loss of material on external surfaces of carbon steel piping exposed to condensation. Therefore, loss of material is an appropriate aging effect for this material/environment combination. However, the piping component of interest is internal to the CST. Therefore, use of the External Surfaces Monitoring Program is not practical. The staff notes that during normal operation, the tank vapor space is blanketed with nitrogen which will reduce the presence of oxygen. The staff agrees that consideration of condensation as an environment is conservative. The applicant proposed to use the water chemistry control program in lieu the External Surfaces Monitoring Program. The staff finds that use of the Water Chemistry Control – Primary and Secondary Program is acceptable because the program periodically monitors and controls known detrimental contaminants such as chlorides, fluorides, dissolved oxygen, and sulfate concentrations below the levels known to result in loss of material or cracking. Additionally, water chemistry control is in accordance with industry guideline EPRI TR-102134 for secondary water chemistry in PWRs. As noted previously, the presence of oxygen which contributes to loss of material is reduced by the presence of the nitrogen blanket. Based on the above, the staff finds the applicant's AMR results acceptable.

In LRA Table 3.4.2-3-IP2, the applicant applied Note G and identified the loss of material as the aging effect for carbon steel tanks exposed to concrete and oiled sand (external) and proposed the Aboveground Steel Tanks Program to manage this aging effect. The staff's review of the

Aboveground Steel Tanks Program is documented in SER Section 3.0.3.2.1. The staff finds this acceptable because the staff has accepted considering steel tanks exposed to concrete and oiled sand bounded by steel tanks exposed to soil which is in the GALL Report.

In LRA Table 3.4.2-3-IP2, the applicant applied Note G and identified the loss of material as the aging effect for copper alloy tubing exposed to steam (internal) and proposed the Water Chemistry Control – Primary and Secondary to manage this aging effect. The staff's review of Water Chemistry Control – Primary and Secondary Program is documented in SER Section 3.0.3.2.17. Based on the review of this program, the staff finds the proposed program acceptable for managing loss of material due to exposure to steam (internal) because American Society of Metals (ASM) Handbook, Volume 13B, "Corrosion of Metals," page 138, 2005 states that steam is not corrosive to copper alloys as long as levels of carbon dioxide, oxygen, and ammonia remain low. These species will be controlled by the Water Chemistry Control – Primary and Secondary to manage this aging effect.

In LRA Table 3.4.2-3-IP2, the applicant applied Note H and identified "cracking–fatigue" as the aging effect for stainless steel piping, piping components, and tubing exposed to steam (internal). The applicant referenced this combination as a metal fatigue TLAA. The staff's evaluation of the metal fatigue TLAAs is documented in SER Section 4.3.2. During an audit, the staff questioned the applicant about these AMR results, to gain a better understanding of the conditions and how cracking would be managed (Audit Item 233). In its response, dated December 18, 2007, the applicant provided additional explanation of the conditions potentially leading to cracking and the consequences of a crack on performance of intended function. The staff reviewed this information and concluded that the applicant has been conservative in postulating potential cracking and in assessing the potential consequences. Therefore, the staff finds the applicant's AMR results acceptable.

The applicant has credited the Fatigue Monitoring Program with managing this aging effect. The staff reviewed and evaluated the proposed Fatigue Monitoring Program and documents its evaluation in SER Section 3.0.3.2.6. Based on its review, the staff finds the proposed program acceptable for managing cracking due to fatigue in stainless steel piping and piping components exposed to steam. The ASME Boiler & Pressure Vessel Code, Section III gives curves for fatigue of stainless steel and the Fatigue Monitoring Program is a conservative way to manage this aging effect.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of combinations of material, environment, AERM, and AMP not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed, so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4A.2.3.4 Steam Generator Blowdown System—Summary of Aging Management Review—LRA Table 3.4.2-4-IP2

The staff reviewed LRA Table 3.4.2-4-IP2, which summarizes the results of AMR evaluations for the SG blowdown system component groups.

In LRA Table 3.4.2-4-IP2, the applicant used Note I and identified no aging effect for the carbon steel bolting, piping, and valve bodies externally exposed to the plant indoor air environment.

Note I for these AMR lines is further supplemented by the plant-specific Note 401, which states that the applicable components are not subject to moisture condensation because they remain at high temperatures during normal plant operation. The components have a similar material and environment as Item SP-1 in the GALL Report, which is applicable to the steel piping, piping components, and piping elements in an external environment of indoor air and does not require an AERM or AMP. On the basis that the LRA components are similar to other GALL Report items for the material and environment (e.g., GALL Report, Volume 2, Item V.F-16, whereby the AERM is listed as "none," the AMP is listed as "none," and no further evaluation is required), the staff finds that the effect of plant indoor air on steel components at elevated temperatures will not result in aging that will be of concern during the period of extended operation.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of combinations of material, environment, AERM, and AMP not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed, so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4A.2.3.5 IP2 Auxiliary Feedwater Pump Room Fire Event—Summary of Aging Management Review—LRA Tables 3.4.2-5-1-IP2 through 3.4.2-5-13-IP2

The staff reviewed LRA Tables 3.4.2-5-1-IP2 through 3.4.2-5.13-IP2 which summarize the results of AMR evaluations for the IP2 AFW pump room fire event component groups.

LRA Table 3.4.2-5-2-IP2 Condensate System

By letter dated June 12, 2009, the applicant amended its LRA to include AMR line items for the following material/environment/aging effect combinations: titanium heat exchanger tubes exposed to externally to steam with an aging effect of loss of material and fouling; stainless steel heat exchanger tubes exposed externally to steam with an aging effect of fouling; and titanium heat exchanger tubes exposed internally to treated water with an aging effect of loss of material and fouling. The applicant proposed to manage these aging effects by using the Water Chemistry Control – Primary and Secondary program. The staff documents its review of the Water Chemistry Control – Primary and Secondary program in SER Section 3.0.3.2.17. The Water Chemistry Control - Primary and Secondary Program includes preventive measures that manage loss of material, cracking, or fouling for these components and follows EPRI Guidelines in TR-105714, Rev. 5, Pressurized Water Reactor Primary Water Chemistry Guidelines, and TR-102134, Rev. 6, Pressurized Water Reactor Secondary Chemistry Guidelines. Because this system is non-safety related, and the applicant is adhering to appropriate EPRI Guidelines, the staff finds that this aging effect will be effectively managed by this program.

By letter dated June 12, 2009, the applicant amended its LRA to state that titanium heat exchanger tubes exposed internally to raw water with an aging effect of fouling and loss of material will be managed by using the Periodic Surveillance and Preventive Maintenance Program. The staff's review of the Periodic Surveillance and Preventive Maintenance Program is documented in SER Section 3.0.3.3.7. The Periodic Surveillance and Preventive Maintenance Program enhancements add new activities to the plant's preventive maintenance and surveillance programs, which implement preventive maintenance and surveillance testing

activities through repetitive tasks or routine monitoring of plant operations. On the basis of its review, the staff finds that because these components will be inspected periodically for loss of material and fouling, the aging effect for the component, material and environment combination will be effectively managed by this aging management program.

<u>LRA Table 3.4.2-5-3-IP2 Circulating Water System</u>

By letter dated June 12, 2009, the applicant added line items with Note G for elastomer expansion joints exposed externally to outdoor air with the aging effects of cracking and change of material properties. Note G is environment not in GALL for this component and material. The applicant proposes to manage the effects of aging using the Periodic Surveillance and Preventive Maintenance Program. The staff's review of the Periodic Surveillance and Preventive Maintenance Program is documented in SER section 3.0.3.3.7. The Periodic Surveillance and Preventive Maintenance Program enhancements add new activities to the plant's preventive maintenance and surveillance programs, which implement preventive maintenance and surveillance testing activities through repetitive tasks or routine monitoring of plant operations. On the basis of its review, the staff finds that because these components will be inspected periodically for cracking and change of material properties, the aging effect for the component, material and environment combination will be effectively managed by this aging management program.

<u>LRA Table 3.4.2-5-4-IP2 City Water System</u>

By letter dated June 12, 2009, the applicant added line items with Note G for carbon steel piping, sight glasses, and strainer bodies exposed to treated water on the inside with an aging effect of loss of material. Note G is environment not in GALL for this component and material. The applicant proposes to manage the effects of aging using the Periodic Surveillance and Preventive Maintenance Program. The staff's review of the Periodic Surveillance and Preventive Maintenance Program is documented in SER section 3.0.3.3.7. The Periodic Surveillance and Preventive Maintenance Program enhancements add new activities to the plant's preventive maintenance and surveillance programs, which implement preventive maintenance and surveillance testing activities through repetitive tasks or routine monitoring of plant operations. On the basis of its review, the staff finds that because these components will be inspected periodically for cracking and change of material properties, the aging effect for the component, material and environment combinations will be effectively managed by this AMP.

In a letter dated June 12, 2009, the applicant referenced Note G for stainless steel bolting, piping, tubing, and valve bodies exposed to an external environment of outdoor air, with the aging effect of loss of material. Note G is environment not in GALL Report for this component and material. The applicant proposed to manage the effects of aging of bolting components by the Bolting Integrity Program. The staff's evaluation of these programs is documented in SER Section 3.0.3.2.2. The Bolting Integrity Program conducts inspections of bolting in accordance with the ASME Code, Section XI, Tables IWB 2500-1, IWC 2500-1 and IWD 2500-1, using visual techniques to inspect for leakage, loss of material, cracking, and loss of preload/loss of prestress. The applicant proposed to manage the effects of aging for piping, tubing and valve bodies exposed externally to outdoor air by using the External Surfaces Monitoring Program. The staff's review of the External Surfaces Monitoring Program is documented in SER section 3.0.3.2.5. The staff determined that this program will perform periodic visual inspections which will be capable of detecting loss of material and evidence of corrosion in these stainless

steel components. On the basis of its review, the staff finds that, because these components will be inspected periodically for loss of material, the aging effect for the component, material and environment combinations will be effectively managed by this program.

In a letter dated June 12, 2009, the applicant referenced Note G, Note 407 for stainless steel flexible hose, piping, strainer, strainer housing, tubing and valve bodies exposed internally to treated water with the aging effect of loss of material. Note G is environment not in GALL Report for this component and material. Note 407 states: "This treated water environment includes water that has been treated but is not maintained by a chemistry control program, such as water from the city water system. There is no environment in NUREG-1801 that will support a useful comparison for this line." The applicant proposed to manage the aging using the One-Time Inspection Program. The staff's evaluation of this program is documented in SER Section 3.0.3.1.9. The staff notes that it is not anticipated that city water will attack stainless steel components because stainless steel is commonly used to contain potable water supplies. The staff notes the use of the One-Time Inspection Program will verify that corrosion is not occurring or, if loss of material is identified during the one-time inspection, a corrective action report will be prepared and an evaluation will be conducted which may result in additional inspections of these components. On the basis of its review, the staff finds that, because these components will be inspected to confirm whether loss of material has occurred and additional inspections may be conducted if degradation is found, the aging effect for the component, material and environment combinations will be effectively managed by this program.

In a letter dated June 12, 2009, the applicant referenced Note G, Note 407, for sight glasses exposed externally to outdoor air and internally to treated water with no aging effect and no aging management program required. Note G is environment not in GALL Report for this component and material. The staff notes that GALL AMR Line Item V.F-10 states that glass exposed to air does not experience an aging effect requiring management. The staff further notes that GALL AMR Line Item VII.J-7 states that glass exposed to treated water does not experience an aging effect requiring management. The staff determines that sight glasses exposed to outdoor air and treated water do not have an aging effect requiring management. On the basis of its review, the staff finds that because the applicant's determination is consistent with the recommendations of the GALL Report for glass exposed to outdoor air and treated water, the applicant has appropriately concluded that these components do not experience an aging effect requiring management.

In a letter dated June 12, 2009, the applicant referenced Note G, Note 407, for copper alloy with greater than 15 percent zinc strainer housing exposed on the interior to treated water with an aging effect of loss of material. Note G is environment not in GALL Report for this component and material. The applicant proposes that the aging effects be managed using the Periodic Surveillance and Preventive Maintenance Program and the Selective Leaching Program. The staff's review of the Periodic Surveillance and Preventive Maintenance Program is documented in SER Section 3.0.3.3.7. The staff's review of the Selective Leaching Program is documented in SER Section 3.0.3.1.13. The Periodic Surveillance and Preventive Maintenance Program enhancements add new activities to the plant's preventive maintenance and surveillance programs, which generally implement preventive maintenance and surveillance testing activities through repetitive tasks or routine monitoring of plant operations. On the basis of its review, the staff finds that because these components will be inspected periodically for loss of material, the aging effect for the component, material and environment combination will be effectively managed by the Periodic Surveillance and Preventive Maintenance Program. The

Selective Leaching Program will include a one-time visual inspection, hardness measurement (where feasible based on form and configuration) or other industry-accepted mechanical inspection techniques of selected components that may be susceptible to selective leaching to determine whether loss of material due to selective leaching has occurred and whether the process will affect component ability to perform intended functions during the period of extended operation. On the basis of its review, the staff finds that the Selective Leaching Program will determine if selective leaching has occurred and if so, it will be evaluated to determine if additional inspections are required. Accordingly, the staff finds that the aging effects for these component, material and environment combinations will be effectively managed by these programs.

LRA Table 3.4.3.-5-5-IP2 Wash Water System

In a letter dated June 9, 2009, the applicant referenced Note G, for stainless steel bolting exposed to outdoor air with an aging effect of loss of material. Note G is environment not in GALL Report for this component and material. The applicant proposed using the Bolting Integrity Program to manage the effects of aging. The staff's evaluation of this program is documented in SER Section 3.0.3.2.2. The Bolting Integrity Program conducts inspections of bolting in accordance with the ASME Section XI, Tables IWB 2500-1, IWC 2500-1 and IWD 2500-1, using visual techniques to inspect for leakage, loss of material, cracking, and loss of preload/loss of prestress. On the basis of its review, the staff finds that, because these components will be inspected periodically for loss of material, the aging effect for the component, material and environment combination will be effectively managed by this program.

In a letter dated June 12, 2009, the applicant referenced Note G, for elastomer expansion joints exposed to outdoor air with the aging effects of cracking and change of material properties. Note G is environment not in GALL Report for this component and material. The applicant proposes to manage the effects of aging using the Periodic Surveillance and Preventive Maintenance Program. The staff's review of the Periodic Surveillance and Preventive Maintenance Program is documented in SER section 3.0.3.3.7. The Periodic Surveillance and Preventive Maintenance Program enhancements add new activities to the plant's preventive maintenance and surveillance programs, which generally implement preventive maintenance and surveillance testing activities through repetitive tasks or routine monitoring of plant operations. On the basis of its review, the staff finds that because these components will be inspected periodically for cracking and change of material properties, the aging effect for the component, material and environment combination will be effectively managed by this AMP.

In a letter dated June 12, 2009, the applicant referenced Note G for stainless steel flexible hose, piping, pump casing, tubing and valve bodies exposed to an externally to outdoor air, with the aging effect of loss of material. Note G is environment not in GALL Report for this component and material. The applicant proposed using the External Surfaces Monitoring Program to manage this aging effect. The staff's review of the External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.5. This program involves periodic visual inspection of SSCs in scope for license renewal to identify evidence of corrosion. On the basis of its review, the staff finds that because these components will be inspected periodically for signs of corrosion, the aging effect for the component, material and environment combinations will be effectively managed by this AMP.

LRA Table 3.4.2-5-7-IP2 Instrument Air System

By letter dated June 12, 2009, the applicant referenced Note G, for stainless steel bolting exposed to outdoor air with an aging effect of loss of material. Note G is environment not in GALL Report for this component and material. The applicant proposed using the Bolting Integrity Program to manage the effects of aging. The staff's evaluation of this program is documented in SER Section 3.0.3.2.2. The Bolting Integrity Program conducts inspections of bolting in accordance with the ASME Code, Section XI, Tables IWB 2500-1, IWC 2500-1 and IWD 2500-1, using visual techniques to inspect for leakage, loss of material, cracking, and loss of preload/loss of prestress. On the basis of its review, the staff finds that, because these components will be inspected periodically for loss of material, the aging effect for the component, material and environment combination will be effectively managed by this program.

By letter dated June 12, 2009, the applicant referenced Note G, Note 407, for copper alloy with greater than 15 percent zinc heat exchanger tubes exposed on the interior to condensation with an aging effect of loss of material. Note G is environment not in GALL Report for this component and material. The applicant proposes that the aging effects be managed using the Periodic Surveillance and Preventive Maintenance Program. The staff's review of the Periodic Surveillance and Preventive Maintenance Program is documented in SER Section 3.0.3.3.7. The Periodic Surveillance and Preventive Maintenance Program enhancements add new activities to the plant's preventive maintenance and surveillance programs, which generally implement preventive maintenance and surveillance testing activities through repetitive tasks or routine monitoring of plant operations. On the basis of its review, the staff finds that because these components will be inspected periodically for loss of material, the aging effect for the component, material and environment combination will be effectively managed by the Periodic Surveillance and Preventive Maintenance Program.

LRA Table 3.4.2-5-9-IP2 Service Water System

In a letter dated June 12, 2009, the applicant referenced Note E, for stainless steel bolting exposed to condensation with an aging effect of loss of material. Note E is defined as the AMR is consistent with the GALL Report AMR result for material, environment and aging effect, but a different AMP is credited, or the GALL Report identifies that a plant-specific AMP should be used. The applicant proposed using the Bolting Integrity Program to manage the effects of aging. The staff's evaluation of this program is documented in SER Section 3.0.3.2.2. The Bolting Integrity Program conducts inspections of bolting in accordance with the ASME Section XI, Tables IWB 2500-1, IWC 2500-1 and IWD 2500-1, using visual techniques to inspect for leakage, loss of material, cracking, and loss of preload/loss of prestress. On the basis of its review, the staff finds that, because these components will be inspected periodically for loss of material, the aging effect for the component, material and environment combination will be effectively managed by this AMP.

By letter dated June 12, 2009, the applicant referenced Note E for stainless steel piping tubing and valve bodies and copper alloy tubing exposed to an external environment of condensation, with the aging effect of loss of material. Note E is defined as the AMR is consistent with the GALL Report AMR result for material, environment and aging effect, but a different AMP is credited, or the GALL Report identifies that a plant-specific AMP should be used. The applicant proposed using the External Surfaces Monitoring Program to manage this aging effect. The staff's review of the External Surfaces Monitoring Program is documented in SER

Section 3.0.3.2.5. This program involves visual inspection of SSCs in scope for license renewal to identify evidence of corrosion. On the basis of its review, the staff finds that because these components will be inspected periodically for signs of corrosion, the aging effect for the component, material and environment combinations will be effectively managed by this AMP.

<u>LRA Table 3.4.2-5-10-IP2 Lube Oil System</u>

By letter dated June 12, 2009, the applicant added line items with Note F for titanium heat exchanger tubes exposed internally to lube oil and externally to raw water with the aging effects of fouling and loss of material. Note F is material not in the GALL Report for this component. The applicant proposed to manage these aging effects by using the Oil Analysis Program for the lube oil environment and the Service Water Integrity Program for the raw water environment. The staff's evaluation of the Oil Analysis Program is documented in SER Section 3.0.3.2.12. The Oil Analysis Program maintains oil systems free of contaminants (primarily water and particulates) to preserve an environment that is not conducive to loss of material, cracking, or fouling. Activities include sampling and analysis of lubricating oil in accordance with industry standards such as ISO 4406, ASTM D445, ASTM D4951, and ASTM D96.The staff's review of the Service Water Integrity Program is documented in SER Section 3.0.3.1.14. The Service Water Integrity Program implements the recommendations of GL 89-13 for managing the effects of aging on the service water (SW) system, during the period of extended operation. The program inspects components for erosion, corrosion, and biofouling to confirm the heat transfer capability of safety-related heat exchangers cooled by SW. Chemical treatment with biocides and sodium hypochlorite and periodic cleaning and flushing of infrequently used loops are methods for controlling fouling within the heat exchangers and managing loss of material in SW components. On the basis of its review, the staff finds that because these components will be inspected periodically for signs of corrosion, the aging effect for the component, material and environment combinations will be effectively managed by these aging management programs.

<u>LRA Table 3.4.2-5-11-IP2 River Water Service System</u>

By letter dated June 12, 2009, the applicant referenced Note G for stainless steel bolting, tubing, and valve bodies exposed to an external environment of outdoor air, with the aging effect of loss of material. Note G is environment not in GALL Report for this component and material. The applicant proposed to manage the effects of aging of bolting components by using the Bolting Integrity Program. The staff's evaluation of these programs is documented in SER Section 3.0.3.2.2. The Bolting Integrity Program conducts inspections of bolting in accordance with the ASME Code, Section XI, Tables IWB 2500-1, IWC 2500-1 and IWD 2500-1, using visual techniques to inspect for leakage, loss of material, cracking, and loss of preload/loss of prestress. The applicant proposed to manage the effects of aging for tubing and valve bodies exposed externally to outdoor air by using the External Surfaces Monitoring Program. The staff's review of the External Surfaces Monitoring Program is documented in SER section 3.0.3.2.5. The staff determined that this program will perform periodic visual inspections which will be capable of detecting loss of material and evidence of corrosion in these stainless steel components. On the basis of its review, the staff finds that, because these components will be inspected periodically for loss of material, the aging effect for the component, material and environment combinations will be effectively managed by this program.

LRA Table 3.4.2-5-12-IP2 Fresh Water Cooling System

By letter dated June 12, 2009, the applicant amended its LRA to state that titanium heat exchanger tubes exposed internally to raw water and externally to treated water with the aging effects of fouling and loss of material, and referenced Note F. Note F indicates that the material is not in the GALL Report for this component. The applicant proposes to manage the effects of aging using the Periodic Surveillance and Preventive Maintenance Program. The staff's review of the Periodic Surveillance and Preventive Maintenance Program is documented in SER Section 3.0.3.3.7. The Periodic Surveillance and Preventive Maintenance Program enhancements add new activities to the plant's preventive maintenance and surveillance programs, which generally implement preventive maintenance and surveillance testing activities through repetitive tasks or routine monitoring of plant operations. On the basis of its review, the staff finds that because these components will be inspected periodically for loss of material and fouling, the aging effect for the component, material and environment combinations will be effectively managed by this aging management program.

LRA Table 3.4.2-5-13-IP2 IP1 Station Air System

The staff reviewed LRA Table 3.4.2-5-13-IP2, which summarizes the results of AMR results for the IP1 station air system with regard to the IP2 AFW pump room fire event. The staff's review *did not identify any line items with plant-specific Notes F through J, indicating that the* combinations of component type, material, environment, and AERM for this system are consistent with the GALL Report.

The staff's evaluation of the line items with Notes A through E is documented in SER Section 3.4.2.1.

3.4B.2.3 IP3 AMR Results Not Consistent with, or Not Addressed in, the GALL Report

In LRA Tables 3.4.2-1-IP3 through 3.4.2-4-IP3, the staff reviewed additional details of the AMR results for combinations of material, environment, AERM, and AMP not consistent with, or not addressed in, the GALL Report.

In LRA Tables 3.4.2-1-IP3 through 3.4.2-4-IP3, the applicant indicated, through Notes F through J, that the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report. The applicant provided further information about how it will manage the aging effects. Specifically, Note F indicates that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR line item combination of component, material, and environment is not evaluated in the GALL Report. Note I indicates that the aging effect identified in the GALL Report for the line item combination of component, material, and environment is not applicable. Note J indicates that neither the component nor the combination of material and environment for the line item is evaluated in the GALL Report.

For combinations of component type, material, and environment not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant has demonstrated that the effects of aging will be adequately managed so that the intended

functions will be maintained consistent with the CLB for the period of extended operation. The staff documents its evaluation in the following sections.

3.4B.2.3.1 Main Steam System—Summary of Aging Management Review—
LRA Table 3.4.2-1-IP3

The staff reviewed LRA Table 3.4.2-1-IP3, which summarizes the results of AMR evaluations for the main steam system component groups.

In LRA Table 3.4.2-1-IP3, the applicant used Note I and identified no aging effect for the carbon steel bolting, piping, and piping components such as steam trap, flow element, strainer housing, and valve bodies, externally exposed to the plant indoor air environment. Note I for these AMR lines is further supplemented by the plant-specific Note 401, which implies that these components are not subject to moisture condensation because they remain at high temperatures during normal plant operation. These components have a similar material and environment as Item SP-1 in the GALL Report, which is applicable to the steel piping, piping components, and piping elements in an external environment of indoor air and does not require an AERM or AMP. On the basis that the LRA components are similar to other GALL Report items for the material and environment (e.g., GALL Report, Volume 2, Table V.F, Line Item V.F-16, whereby the AERM is listed as "none," the AMP is listed as "none," and no further evaluation is required), the staff finds that the effect of plant indoor air on steel components at elevated temperatures will not result in aging that will be of concern during the period of extended operation.

In LRA Table 3.4.2-1-IP3, the applicant applied Note H and identified "cracking–fatigue" as the aging effect for stainless steel piping, piping components, piping elements, tubing, strainers, thermowells, and valve bodies exposed to steam (internal). The applicant has credited the Fatigue Monitoring Program with managing this aging effect. The staff reviewed and evaluated the proposed Fatigue Monitoring Program and documents its evaluation in Section 3.0.3.2.6. Based on its review, the staff finds the proposed program acceptable for managing cracking due to fatigue in stainless steel piping and piping components exposed to steam. The ASME Boiler & Pressure Vessel Code, Section III gives curves for fatigue of stainless steel and the Fatigue Monitoring Program is a conservative way to manage this aging effect.

In LRA Table 3.4.2-1-IP3, the applicant applied Note F and identified "cracking–fatigue" as the aging effect for stainless steel strainers exposed to steam (external). The applicant has credited the Fatigue Monitoring Program with managing this aging effect. The staff reviewed and evaluated the proposed Fatigue Monitoring Program and documents its evaluation in Section 3.0.3.2.6. Based on its review, the staff finds the proposed program acceptable for managing cracking due to fatigue in stainless steel piping and piping components exposed to steam. The ASME Boiler & Pressure Vessel Code, Section III gives curves for fatigue of stainless steel and the Fatigue Monitoring Program is a conservative way to manage this aging effect.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of combinations of material, environment, AERM, and AMP not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed, so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4B.2.3.2 Main Feedwater System—Summary of Aging Management Review—LRA Table 3.4.2-2-IP3

The staff reviewed LRA Table 3.4.2-2-IP3, which summarizes the results of AMR evaluations for the main feedwater system component groups.

In LRA Table 3.4.2-2-IP3, the applicant used Note I and identified no aging effects for the carbon steel bolting, piping, and valve bodies externally exposed to the plant indoor air environment. Note I for these AMR lines is further supplemented by the plant-specific Note 401, which implies that the applicable components are not subject to moisture condensation because they remain at high temperatures during normal plant operation. The components have a similar material and environment as Item SP-1 in the GALL Report, which is applicable to the steel piping, piping components, and piping elements in an external environment of indoor air and does not require an AERM or AMP. On the basis that the LRA components are similar to other GALL Report items for the material and environment (e.g., GALL Report, Volume 2, Table V.F, Line Item V.F-16, whereby the AERM is listed as "none," the AMP is listed as "none," and no further evaluation is required), the staff finds that the effect of plant indoor air on steel components at elevated temperatures will not result in aging that will be of concern during the period of extended operation.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of combinations of material, environment, AERM, and AMP not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4B.2.3.3 Auxiliary Feedwater System—Summary of Aging Management Review—LRA Table 3.4.2-3-IP3

The staff reviewed LRA Table 3.4.2-3-IP3, which summarizes the results of AMR evaluations for the AFW system component groups.

In LRA Table 3.4.2-3-IP3, the applicant applied Note F and identified "cracking–fatigue" as the aging effect for stainless steel strainer exposed to steam (external). The applicant has credited the Fatigue Monitoring Program with managing this aging effect. The staff reviewed and evaluated the proposed Fatigue Monitoring Program and documents its evaluation in SER Section 3.0.3.2.6. Based on the review of this program, the staff finds the proposed program acceptable for managing cracking due to fatigue in stainless steel piping and piping components such as strainers exposed to steam. The ASME Boiler & Pressure Vessel Code, Section III gives curves for fatigue of stainless steel and the Fatigue Monitoring Program is a conservative way to manage this aging effect.

In LRA Table 3.4.2-3-IP3, the applicant proposed using the External Surfaces Monitoring Program to manage the loss of material in stainless steel piping, tubing, and valve bodies exposed to an external environment of outdoor air. The applicant applied Note G to indicate that the environment for these components and material is not included in the GALL Report. The staff finds that the applicant's External Surfaces Monitoring Program includes periodic visual inspections of external surfaces during the system engineer's walkdowns of the systems. The

staff evaluates the External Surfaces Monitoring Program in SER Section 3.0.3.2.5. The staff finds that the aging effect of the loss of material in stainless steel piping and tanks exposed to an external environment of outdoor air will be adequately managed by using the External Surfaces Monitoring Program.

In LRA Table 3.4.2-3-IP3, the applicant proposed using the Bolting Integrity Program to manage the loss of material in stainless steel bolting exposed to the outdoor air (external) environment. The applicant applied Note G to indicate that the environment for this component and material is not included in the GALL Report. The staff documents its evaluation of the Bolting Integrity Program in SER Section 3.0.3.2.2. This program is also recommended in the GALL Report, Table 4, Item 22, to manage the loss of material due to general, pitting, and crevice corrosion in steel bolting exposed to outdoor air (external). Based on the above, the staff finds that the aging effect of the loss of material in these components will be adequately managed by using the Bolting Integrity Program.

In LRA Table 3.4.2-3-IP3, the applicant applied Note G and identified the loss of material as the aging effect for carbon steel tanks exposed to concrete and oiled sand (external) and proposed the Aboveground Steel Tanks Program to manage this aging effect. The staff's review of the Aboveground Steel Tanks Program is documented in SER Section 3.0.3.2.1. The staff finds this acceptable because the staff has accepted considering steel tanks exposed to concrete and oiled sand bounded by steel tanks exposed to soil which is in the GALL Report.

In LRA Table 3.4.2-3-IP3, the applicant applied Note G and identified the loss of material as the aging effect for aluminum valve bodies exposed to outdoor air (external) and proposed External Surfaces Monitoring Program to manage the effects of aging. The staff's evaluation of the External Surfaces Monitoring Program is documented in SER Section 3.0.3.2.5. The staff finds this acceptable because the GALL Report has the same material/environment/aging effect/aging management program for different components in GALL Chapter III, Line Items III.B.2-7 and III.4-7.

In LRA Table 3.4.2-3-IP3, the applicant applied Note G and identified the loss of material as the aging effect for copper alloy tubing exposed to steam (internal) and proposed the Water Chemistry Control – Primary and Secondary to manage this aging effect. The staff's review of Water Chemistry Control – Primary and Secondary Program is documented in SER Section 3.0.3.2.17. Based on the review of this program, the staff finds the proposed program acceptable for managing loss of material due to exposure to steam (internal) because ASM Handbook, Volume 13B, "Corrosion of Metals," page 138, 2005 states that steam is not corrosive to copper alloys as long as levels of carbon dioxide, oxygen, and ammonia remain low. These species will be controlled by the Water Chemistry Control – Primary and Secondary to manage this aging effect.

In LRA Table 3.4.2-3-IP3, the applicant applied Note G and plant-specific Note 402 to carbon steel piping externally exposed to condensation with an aging effect of loss of material. Note 402 states, "[t]his environment is inside the condensate storage tank [CST]. The tank vapor space is nitrogen blanketed but the environment is conservatively assumed to be condensation." The applicant proposed the Water Chemistry Control – Primary and Secondary Program to manage the effects of aging. The staff's review of Water Chemistry Control – Primary and Secondary Program is documented in SER Section 3.0.3.2.17. The staff's evaluation of this component/material/environment/aging effect/AMP combination is

documented in SER Section 3.4A.2.3.3. As stated in that section, the staff finds the applicant's AMR results acceptable.

In LRA Table 3.4.2-3-IP3, the applicant proposed using the One-Time Inspection Program to manage the loss of material in stainless steel tubing and valve bodies exposed to treated water (internal) environment. The applicant applied Note G and plant-specific Note 407 to indicate that the environment for these components and material is not included in the GALL Report. The staff finds that the applicant's One-Time Inspection Program will use inspections to detect whether these components are incurring a loss of material. The program uses both visual and NDE techniques for inspection. The program includes a provision that any unacceptable results or findings will be evaluated in accordance with the site corrective action process to determine the need for subsequent (including periodic) inspections. The staff evaluates the External Surfaces Monitoring Program in SER Section 3.0.3.1.9. Based on the above, the staff finds that the aging effect of the loss of material in these components will be adequately managed by using the One-Time Inspection Program.

In LRA Table 3.4.2-3-IP3, the applicant applied Note G and plant-specific Note 407, and identified the loss of material as the aging effect for carbon steel piping and valve bodies exposed to the treated water (internal) environment. The applicant has credited the Periodic Surveillance and Preventive Maintenance Program with managing this aging effect. The staff reviewed and evaluated the proposed Periodic Surveillance and Preventive Maintenance Program and documents its evaluation in SER Section 3.0.3.3.7. The program includes activities to monitor components to detect degradation and monitor parameters such as wall thickness and surface condition. The program uses both visual and NDE techniques to perform inspections. Based on the review of this program, the staff finds the proposed program acceptable for managing the loss of material in steel piping and piping components such as valve bodies.

In LRA Table 3.4.2-3-IP3, the applicant applied Note H and identified "cracking–fatigue" as the aging effect for stainless steel tubing exposed to steam (internal). Note H indicates that the aging effect is not identified in the GALL Report for the component/material/environment combination. The staff's evaluation of the metal fatigue TLAAs is documented in SER Section 4.3.2. During an audit, the staff questioned the applicant about these AMR results, to gain a better understanding of the conditions and how cracking would be managed (Audit Item 232). In its response, dated December 18, 2007, the applicant provided additional explanation of the conditions potentially leading to cracking and the consequences of a crack on performance of intended function. The staff reviewed this information and concluded that the applicant has been conservative in postulating potential cracking and in assessing the potential consequences. On this basis, the staff finds the applicant's AMR results to be acceptable for these combinations.

In LRA Table 3.4.2-3-IP3, the applicant applied Note H and identified "cracking–fatigue" as the aging effect for stainless steel flex hose, strainer, tubing, and valve body exposed to steam (internal). The applicant stated that this is a TLAA. Note H indicates that the aging effect is not identified in the GALL Report for the component/material/environment combination. The staff's evaluation of the metal fatigue TLAAs is documented in SER Section 4.3.2. During an audit, the staff questioned the applicant about these AMR results, to gain a better understanding of the conditions and how cracking would be managed (Audit Item 232). In its response, dated

December 18, 2007, the applicant provided additional explanation of the conditions potentially leading to cracking and the consequences of a crack on performance of intended function. The staff reviewed this information and concluded that the applicant has been conservative in postulating potential cracking and in assessing the potential consequences. On this basis, the staff finds the applicant's AMR results to be acceptable for these combinations.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of combinations of material, environment, AERM, and AMP not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4B.2.3.4 Steam Generator Blowdown System—Summary of Aging Management Review—LRA Table 3.4.2-4-IP3

The staff reviewed LRA Table 3.4.2-4-IP3, which summarizes the results of AMR evaluations for the SG blowdown system component groups.

In LRA Table 3.4.2-4-IP3, the applicant used Note I and identified no aging effect for the carbon steel bolting, piping, and valve bodies externally exposed to the plant indoor air environment. Note I for these AMR lines is further supplemented by the plant-specific Note 401 which implies that the applicable components are not subject to moisture condensation because they remain at high temperatures during normal plant operation. The components have a similar material and environment as Item SP-1 in the GALL Report, which is applicable to the steel piping, piping components, and piping elements in an external environment of indoor air and does not require an AEM or AMP. On the basis that the LRA components are similar to other GALL Report items for the material and environment (e.g., GALL Report, Volume 2, Table V.F, Line Item V.F-16, whereby the AERM is listed as "none," the AMP is listed as "none," and no further evaluation is required), the staff finds that the effect of plant indoor air on steel components at elevated temperatures will not result in aging that will be of concern during the period of extended operation.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of combinations of material, environment, AERM, and AMP not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed, so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the steam and power conversion system components within the scope of license renewal and subject to an AMR will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5 Aging Management of Containments, Structures, and Component Supports

This section of the SER documents the staff's review of the applicant's AMR results for the containment, structure, and component support components and component groups of:

- containment building
- water control structures
- turbine building, auxiliary building, and other structures
- bulk commodities

3.5.1 Summary of Technical Information in the Application

LRA Section 3.5 provides AMR results for structures, structural components, and component supports. LRA Table 3.5.1, "Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801," is a summary comparison of the applicant's AMRs with those evaluated in the GALL Report.

The applicant's AMRs evaluated and incorporated applicable plant-specific and industry operating experience in the determination of AERMs. The plant-specific evaluation included condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.5.2 Staff Evaluation

The staff reviewed LRA Section 3.5 to determine whether the applicant provided sufficient information to demonstrate that the effects of aging for the containments, structures, and component supports components within the scope of license renewal and subject to an AMR, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff conducted onsite audits of AMRs to ensure the applicant's claim that certain AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Details of the staff's audit evaluation are documented in SER Section 3.5.2.1.

During the onsite audit, the staff also selected AMRs consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations were consistent with the SRP-LR Section 3.5.2.2 acceptance criteria. The staff's audit evaluations are documented in SER Section 3.5.2.2.

The staff also conducted a technical review of the remaining AMRs not consistent with or not addressed in the GALL Report. The technical review evaluated whether all plausible aging effects have been identified and whether the aging effects listed were appropriate for the material-environment combinations specified. The staff's evaluations are documented in SER Section 3.5.2.3.

For structures and components which the applicant claimed were not applicable or required no aging management, the staff reviewed the AMR line items and the plant's operating experience to verify the applicant's claims.

Table 3.5-1 summarizes the staff's evaluation of components, aging effects or mechanisms, and AMPs listed in LRA Section 3.5 and addressed in the GALL Report.

Table 3.5-1 Staff Evaluation for Structures, and Component Supports in the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
PWR Concrete (Reinforced and Prestressed) and Steel Containments					
Concrete elements: walls, dome, basemat, ring girder, buttresses, containment (as applicable). (3.5.1-1)	Aging of accessible and inaccessible concrete areas due to aggressive chemical attack, and corrosion of embedded steel	ISI (IWL) and for inaccessible concrete, an examination of representative samples of below-grade concrete, and periodic monitoring of groundwater if environment is non-aggressive. A plant specific program is to be evaluated if environment is aggressive.	Yes	Containment Inservice Inspection (CII) – IWL, and Structures Monitoring	Consistent with GALL Report after resolution of Open Item 3.5-1 (See SER Section 3.5.2.2.1)
Concrete elements; All (3.5.1-2)	Cracks and distortion due to increased stress levels from settlement	Structures Monitoring Program. If a de-watering system is relied upon for control of settlement, then the licensee is to ensure proper functioning of the de-watering system through the period of extended operation.	Yes	Not applicable	Not applicable (See SER Section 3.5.2.2.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Concrete elements: foundation, sub-foundation (3.5.1-3)	Reduction in foundation strength, cracking, differential settlement due to erosion of porous concrete subfoundation	Structures Monitoring Program If a de-watering system is relied upon to control erosion of cement from porous concrete subfoundations, then the licensee is to ensure proper functioning of the de-watering system through the period of extended operation.	Yes	Not applicable	Not applicable (See SER Section 3.5.2.2.1)
Concrete elements: dome, wall, basemat, ring girder, buttresses, containment, concrete fill-in annulus (as applicable) (3.5.1-4)	Reduction of strength and modulus of concrete due to elevated temperature	A plant-specific aging management program is to be evaluated.	Yes	Not applicable	Not applicable for IP3. Acceptable for IP2 after resolution of Open Item 3.5-2 (See SER Section 3.5.2.2.1)
Steel elements: drywell; torus; drywell head; embedded shell and sand pocket regions; drywell support skirt; torus ring girder; downcomers; liner plate, ECCS suction header, support skirt, region shielded by diaphragm floor, suppression chamber (as applicable) (3.5.1-5)	Loss of material due to general, pitting and crevice corrosion	ISI (IWE) and 10 CFR Part 50, Appendix J	Yes	Not applicable	Not applicable to PWRs (See SER Section 3.5.2.1.1)
Steel elements: steel liner, liner anchors, integral attachments (3.5.1-6)	Loss of material due to general, pitting and crevice corrosion	ISI (IWE) and 10 CFR Part 50, Appendix J	Yes	CII - IWE, Containment Leak Rate, and Structures Monitoring	Consistent with GALL Report (See SER Section 3.5.2.2.1)
Prestressed containment tendons (3.5.1-7)	Loss of prestress due to relaxation, shrinkage, creep, and elevated temperature	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	Not applicable	Not applicable (See SER Section 3.5.2.2.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel and stainless steel elements: vent line, vent header, vent line bellows; downcomers (3.5.1-8)	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	Not applicable	Not applicable to PWRs (See SER Section 3.5.2.1.1)
Steel, stainless steel elements, dissimilar metal welds: penetration sleeves, penetration bellows; suppression pool shell, unbraced downcomers (3.5.1-9)	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	TLAA	Consistent with GALL Report (See SER Section 3.5.2.2.1)
Stainless steel penetration sleeves, penetration bellows, dissimilar metal welds (3.5.1-10)	Cracking due to stress corrosion cracking	ISI (IWE) and 10 CFR Part 50, Appendix J, and additional appropriate examinations/ evaluations for bellows assemblies and dissimilar metal welds.	Yes	Not applicable	Not applicable (See SER Section 3.5.2.2.1)
Stainless steel vent line bellows, (3.5.1-11)	Cracking due to stress corrosion cracking	ISI (IWE) and 10 CFR Part 50, Appendix J, and additional appropriate examination/ evaluation for bellows assemblies and dissimilar metal welds.	Yes	Not applicable	Not applicable to PWRs (See SER Section 3.5.2.1.1)
Steel, stainless steel elements, dissimilar metal welds: penetration sleeves, penetration bellows; suppression pool shell, unbraced downcomers (3.5.1-12)	Cracking due to cyclic loading	ISI (IWE) and 10 CFR Part 50, Appendix J, and supplemented to detect fine cracks	Yes	CII - IWE and Containment Leak Rate	Consistent with GALL Report (See SER Section 3.5.2.2.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel, stainless steel elements, dissimilar metal welds: torus; vent line; vent header; vent line bellows; downcomers (3.5.1-13)	Cracking due to cyclic loading	ISI (IWE) and 10 CFR Part 50, Appendix J, and supplemented to detect fine cracks	Yes	Not applicable	Not applicable to PWRs (See SER Section 3.5.2.1.1)
Concrete elements: dome, wall, basemat ring girder, buttresses, containment (as applicable) (3.5.1-14)	Loss of material (scaling, cracking, and spalling) due to freeze-thaw	ISI (IWL). Evaluation is needed for plants that are located in moderate to severe weathering conditions (weathering index > 100 day-inch/yr) (NUREG-1557).	Yes	CII – IWL and Structures Monitoring	See SER Section 3.5.2.2.1
Concrete elements: walls, dome, basemat, ring girder, buttresses, containment, concrete fill-in annulus (as applicable). (3.5.1-15)	Cracking due to expansion and reaction with aggregate; increase in porosity, permeability due to leaching of calcium hydroxide	ISI (IWL) for accessible areas. None for inaccessible areas if concrete was constructed in accordance with the recommendations in ACI 201.2R.	Yes	CII – IWL and Structures Monitoring	See SER Section 3.5.2.2.1
Seals, gaskets, and moisture barriers (3.5.1-16)	Loss of sealing and leakage through containment due to deterioration of joint seals, gaskets, and moisture barriers (caulking, flashing, and other sealants)	ISI (IWE) and 10 CFR Part 50, Appendix J	No	CII – IWE and Containment Leak Rate	Consistent with GALL Report
Personnel airlock, equipment hatch and CRD hatch locks, hinges, and closure mechanisms (3.5.1-17)	Loss of leak tightness in closed position due to mechanical wear of locks, hinges and closure mechanisms	10 CFR Part 50, Appendix J and plant Technical Specifications	No	Containment Leak Rate, CII – IWE, and plant Technical Specifications	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP In GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel penetration sleeves and dissimilar metal welds; personnel airlock, equipment hatch and CRD hatch (3.5.1-18)	Loss of material due to general, pitting, and crevice corrosion	ISI (IWE) and 10 CFR Part 50, Appendix J	No	CII – IWE and Containment Leak Rate	Consistent with GALL Report
Steel elements: stainless steel suppression chamber shell (inner surface) (3.5.1-19)	Cracking due to stress corrosion cracking	ISI (IWE) and 10 CFR Part 50, Appendix J	No	Not applicable	Not applicable to PWRs (See SER Section 3.5.2.1.1)
Steel elements: suppression chamber liner (interior surface) (3.5.1-20)	Loss of material due to general, pitting, and crevice corrosion	ISI (IWE) and 10 CFR Part 50, Appendix J	No	Not applicable	Not applicable to PWRs (See SER Section 3.5.2.1.1)
Steel elements: drywell head and downcomer pipes (3.5.1-21)	Fretting or lock up due to mechanical wear	ISI (IWE)	No	Not applicable	Not applicable to PWRs (See SER Section 3.5.2.1.1)
Prestressed containment: tendons and anchorage components (3.5.1-22)	Loss of material due to corrosion	ISI (IWL)	No	Not applicable	Not applicable to IP (See SER Section 3.5.2.1.1)
Safety-Related and Other Structures; and Component Supports					
All Groups except Group 6: interior and above grade exterior concrete (3.5.1-23)	Cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel	Structures Monitoring Program	Yes	CII – IWL and Structures Monitoring	Consistent with GALL Report (See SER Section 3.5.2.2.2)
All Groups except Group 6: interior and above grade exterior concrete (3.5.1-24)	Increase in porosity and permeability, cracking, loss of material (spalling, scaling) due to aggressive chemical attack	Structures Monitoring Program	Yes	CII – IWL, supplemented by Structures Monitoring	Consistent with GALL Report (See SER Section 3.5.2.2.2)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
All Groups except Group 6: steel components: all structural steel (3.5.1-25)	Loss of material due to corrosion	Structures Monitoring Program. If protective coatings are relied upon to manage the effects of aging, the Structures Monitoring Program is to include provisions to address protective coating monitoring and maintenance.	Yes	Structures Monitoring, supplemented by Fire Protection	Consistent with GALL Report (See SER Section 3.5.2.2.2)
All Groups except Group 6: accessible and inaccessible concrete: foundation (3.5.1-26)	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Structures Monitoring Program. Evaluation is needed for plants that are located in moderate to severe weathering conditions (weathering index > 100 day-inch/yr) (NUREG-1557).	Yes	CII – IWL, supplemented by Structures Monitoring. In some cases, Structures Monitoring is supplemented by Fire Protection	See SER Section 3.5.2.2.2
All Groups except Group 6: accessible and inaccessible interior/exterior concrete (3.5.1-27)	Cracking due to expansion due to reaction with aggregates	Structures Monitoring Program. None for inaccessible areas if concrete was constructed in accordance with the recommendations in ACI 201.2R-77.	Yes	CII – IWL, supplemented by Structures Monitoring.	See SER Section 3.5.2.2.2
Groups 1-3, 5-9: All (3.5.1-28)	Cracks and distortion due to increased stress levels from settlement	Structures Monitoring Program. If a de-watering system is relied upon for control of settlement, then the licensee is to ensure proper functioning of the de-watering system through the period of extended operation.	Yes	Not applicable	Not applicable (See SER Section 3.5.2.2.2)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Groups 1-3, 5-9: foundation (3.5.1-29)	Reduction in foundation strength, cracking, differential settlement due to erosion of porous concrete subfoundation	Structures Monitoring Program. If a de-watering system is relied upon for control of settlement, then the licensee is to ensure proper functioning of the de-watering system through the period of extended operation.	Yes	Not applicable	Not applicable (See SER Section 3.5.2.2.2)
Group 4: radial beam seats in BWR drywell; RPV support shoes for PWR with nozzle supports; steam generator supports (3.5.1-30)	Lock-up due to wear	ISI (IWF) or Structures Monitoring Program	Yes	Inservice Inspection (ISI) – IWF	Consistent with GALL Report (See SER Section 3.5.2.2.2)
Groups 1-3, 5, 7-9: below-grade concrete components, such as exterior walls below grade and foundation (3.5.1-31)	Increase in porosity and permeability, cracking, loss of material (spalling, scaling), aggressive chemical attack; cracking, loss of bond, and loss of material (spalling, scaling), corrosion of embedded steel	Structures Monitoring Program; examination of representative samples of below-grade concrete, and periodic monitoring of groundwater, if the environment is non-aggressive. A plant specific program is to be evaluated if environment is aggressive.	Yes	Structures Monitoring	See SER Section 3.5.2.2.2
Groups 1-3, 5, 7-9: exterior above and below grade reinforced concrete foundations (3.5.1-32)	Increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide	Structures Monitoring Program for accessible areas. None for inaccessible areas if concrete was constructed in accordance with the recommendations in ACI 201.2R-77.	Yes	Structures Monitoring	See SER Section 3.5.2.2.2
Groups 1-5: concrete (3.5.1-33)	Reduction of strength and modulus due to elevated temperature	A plant-specific aging management program is to be evaluated	Yes	Structures Monitoring	Not applicable (See SER Section 3.5.2.2.2)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Group 6: concrete; all (3.5.1-34)	Increase in porosity and permeability, cracking, loss of material due to aggressive chemical attack; cracking, loss of bond, loss of material due to corrosion of embedded steel	Inspection of Water-Control Structures or FERC/US Army Corps of Engineers dam inspections and maintenance programs and for inaccessible concrete, an examination of representative samples of below-grade concrete, and periodic monitoring of groundwater, if the environment is non-aggressive. A plant specific program is to be evaluated if environment is aggressive.	Yes	Structures Monitoring	See SER Section 3.5.2.2.2
Group 6: exterior above and below grade concrete foundation (3.5.1-35)	Loss of material (spalling, scaling) and cracking due to freeze-thaw	Inspection of Water-Control Structures or FERC/US Army Corps of Engineers dam inspections and maintenance programs. Evaluation is needed for plants that are located in moderate to severe weathering conditions (weathering index > 100 day-inch/yr) (NUREG-1557).	Yes	Structures Monitoring	See SER Section 3.5.2.2.2
Group 6: all accessible and inaccessible reinforced concrete (3.5.1-36)	Cracking due to expansion/reaction with aggregates	Accessible areas: Inspection of Water-Control Structures or FERC/US Army Corps of Engineers dam inspections and maintenance programs. None for inaccessible areas if concrete was constructed in accordance with the recommendations in ACI 201.2R-77.	Yes	Structures Monitoring	See SER Section 3.5.2.2.2

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Group 6: exterior above and below grade reinforced concrete foundation interior slab (3.5.1-37)	Increase in porosity and permeability, loss of strength due to leaching of calcium hydroxide	For accessible areas, Inspection of Water-Control Structures or FERC/US Army Corps of Engineers dam inspections and maintenance programs. None for inaccessible areas if concrete was constructed in accordance with the recommendations in ACI 201.2R-77.	Yes	Structures Monitoring	See SER Section 3.5.2.2.2
Groups 7, 8: tank liners (3.5.1-38)	Cracking due to stress corrosion cracking; loss of material due to pitting and crevice corrosion	A plant-specific aging management program is to be evaluated	Yes	Not applicable	Not applicable (See SER Sections 3.5.2.1.2 and 3.5.2.2.2)
Support members; welds; bolted connections; support anchorage to building structure (3.5.1-39)	Loss of material due to general and pitting corrosion	Structures Monitoring Program	Yes	Structures Monitoring, supplemented by Fire Protection and Fire Water System	Consistent with GALL Report (See SER Section 3.5.2.2.2)
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates (3.5.1-40)	Reduction in concrete anchor capacity due to local concrete degradation, service-induced cracking or other concrete aging mechanisms	Structures Monitoring Program	Yes	Structures Monitoring	See SER Section 3.5.2.2.2
Vibration isolation elements (3.5.1-41)	Reduction or loss of isolation function, radiation hardening, temperature, humidity, sustained vibratory loading	Structures Monitoring Program	Yes	Not applicable	Not applicable (See SER Sections 3.5.2.1.3 and 3.5.2.2.2)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Groups B1.1, B1.2, and B1.3: support members: anchor bolts, welds (3.5.1-42)	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	Not applicable	Not applicable (See SER Section 3.5.2.2.2)
Groups 1-3, 5, 6: all masonry block walls (3.5.1-43)	Cracking due to restraint shrinkage, creep, and aggressive environment	Masonry Wall Program	No	Masonry Wall, supplemented by Fire Protection in some cases	Consistent with GALL Report
Group 6: elastomer seals, gaskets, and moisture barriers (3.5.1-44)	Loss of sealing due to deterioration of seals, gaskets, and moisture barriers (caulking, flashing, and other sealants)	Structures Monitoring Program	No	Structures Monitoring	Consistent with GALL Report
Group 6: exterior above and below grade concrete foundation; interior slab (3.5.1-45)	Loss of material due to abrasion, cavitation	Inspection of Water-Control Structures or FERC/US Army Corps of Engineers dam inspections and maintenance	No	Structures Monitoring	Consistent with GALL Report
Group 5: fuel pool liners (3.5.1-46)	Cracking due to stress corrosion cracking; loss of material due to pitting and crevice corrosion	Water Chemistry and monitoring of spent fuel pool water level in accordance with technical specifications and leakage from the leak chase channels.	No	Water Chemistry Control – Primary and Secondary, and Technical Specifications (for IP3 only)	Consistent with GALL Report
Group 6: all metal structural members (3.5.1-47)	Loss of material due to general (steel only), pitting and crevice corrosion	Inspection of Water-Control Structures or FERC/US Army Corps of Engineers dam inspections and maintenance. If protective coatings are relied upon to manage aging, protective coating monitoring and maintenance provisions should be included.	No	Structures Monitoring	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Group 6: earthen water control structures - dams, embankments, reservoirs, channels, canals, and ponds (3.5.1-48)	Loss of material, loss of form due to erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, Seepage	Inspection of Water-Control Structures or FERC/US Army Corps of Engineers dam inspections and maintenance programs	No	Not applicable	Not applicable to IP (See SER Section 3.5.2.1.4)
Support members; welds; bolted connections; support anchorage to building structure (3.5.1-49)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and ISI (IWF)	No	Not applicable	Not applicable to PWRs (See SER Section 3.5.2.1.1)
Groups B2, and B4: galvanized steel, aluminum, stainless steel support members; welds; bolted connections; support anchorage to building structure (3.5.1-50)	Loss of material due to pitting and crevice corrosion	Structures Monitoring Program	No	Structures Monitoring	Consistent with GALL Report
Group B1.1: high strength low-alloy bolts (3.5.1-51)	Cracking due to stress corrosion cracking; loss of material due to general corrosion	Bolting Integrity	No	Not applicable	Not applicable (See SER Section 3.5.2.1.5)
Groups B2, and B4: sliding support bearings and sliding support surfaces (3.5.1-52)	Loss of mechanical function due to corrosion, distortion, dirt, overload, fatigue due to vibratory and cyclic thermal loads	Structures Monitoring Program	No	Structures Monitoring	See SER Section 3.5.2.1
Groups B1.1, B1.2, and B1.3: support members: welds; bolted connections; support anchorage to building structure (3.5.1-53)	Loss of material due to general and pitting corrosion	ISI (IWF)	No	Inservice Inspection (ISI) – IWF	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Groups B1.1, B1.2, and B1.3: constant and variable load spring hangers; guides; stops; (3.5.1-54)	Loss of mechanical function due to corrosion, distortion, dirt, overload, fatigue due to vibratory and cyclic thermal loads	ISI (IWF)	No	ISI – IWF	See SER Section 3.5.2.1
Steel, galvanized steel, and aluminum support members; welds; bolted connections; support anchorage to building structure (3.5.1-55)	Loss of material due to boric acid corrosion	Boric Acid Corrosion	No	Boric Acid Corrosion Prevention	Consistent with GALL Report
Groups B1.1, B1.2, and B1.3: sliding surfaces (3.5.1-56)	Loss of mechanical function due to corrosion, distortion, dirt, overload, fatigue due to vibratory and cyclic thermal loads	ISI (IWF)	No	ISI – IWF	Consistent with GALL Report
Groups B1.1, B1.2, and B1.3: vibration isolation elements (3.5.1-57)	Reduction or loss of isolation function, radiation hardening, temperature, humidity, sustained vibratory loading	ISI (IWF)	No	Not applicable	Not applicable to IP (See SER Section 3.5.2.1.3)
Galvanized steel and aluminum support members; welds; bolted connections; support anchorage to building structure exposed to air - indoor uncontrolled (3.5.1-58)	None	None	No	None	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel support members; welds; bolted connections; support anchorage to building structure (3.5.1-59)	None	None	No	None	Consistent with GALL Report

The staff's review of the structures, structural components, and component supports groups followed any one of several approaches. In one approach, documented in SER Section 3.5.2.1, the staff reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and require no further evaluation. In the second approach, documented in SER Section 3.5.2.2, the staff reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. In the third approach, documented in SER Section 3.5.2.3, the staff reviewed AMR results for components that the applicant indicated are not consistent with, or not addressed in, the GALL Report. The staff's review of AMPs credited to manage or monitor aging effects of the structures, structural components, and component supports is documented in SER Section 3.0.3.

3.5.2.1 AMR Results Consistent with the GALL Report

LRA Section 3.5.2.1 identifies the materials, environments, AERMs, and the following programs that manage aging effects for the structures, structural components, and component supports:

- Boric Acid Corrosion Prevention Program
- Containment Leak Rate Program
- Containment Inservice Inspection Program (CII-IWE)
- Containment Inservice Inspection Program (CII-IWL)
- Fire Protection Program
- Fire Water System Program
- Inservice Inspection Program – IWF
- Masonry Wall Program
- Periodic Surveillance and Preventive Maintenance Program
- Structures Monitoring Program
- Water Chemistry Control - Primary and Secondary Program

LRA Tables 3.5.2-1 through 3.5.2-4 summarize the results of the AMRs for the structures, structural components, and component supports, and identify the AMRs which the applicant claims are consistent with the GALL Report. The staff's review of LRA Tables 3.5.2-1 through 3.5.2-4, also included review of the revised LRA Tables 3.5.2-2 and 3.5.2-4 items in Attachment 1 to letter (Amendment 3 to LRA) dated March 24, 2008; and the revised LRA Table 3.5.2-1 items in Attachment 1 to letter (Amendment 5 to LRA) dated June 11, 2008.

For component groups evaluated in the GALL Report, for which the applicant claimed consistency with the report, where the report does not recommend further evaluation, the staff's audit and review determined whether the plant-specific components of these GALL Report component groups were bounded by the GALL Report evaluation.

For each AMR line item, the applicant stated how the information in the tables aligns with the information in the GALL Report. Notes A through E indicate how the AMR is consistent with the GALL Report. The staff audited these AMRs.

Note A indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the GALL Report AMP. The staff audited these line items to verify consistency with the GALL Report and validity of the AMR for the site-specific conditions.

Note B indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the GALL Report AMP. The staff audited these line items to verify consistency with the GALL Report and verified that the identified exceptions to the GALL Report AMPs have been reviewed and accepted. The staff also determined whether the applicant's AMP was consistent with the GALL Report AMP and whether the AMR was valid for the site-specific conditions.

Note C indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the GALL Report AMP. This note indicates that the applicant was unable to find a listing of some system components in the GALL Report; however, the applicant identified in the GALL Report a different component with the same material, environment, aging effect, and AMP as the component under review. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component was applicable to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the GALL Report AMP. The staff audited these line items to verify consistency with the GALL Report. The staff verified whether the AMR line item of the different component was applicable to the component under review and whether the identified exceptions to the GALL Report AMPs have been reviewed and accepted. The staff also determined whether the applicant's AMP was consistent with the GALL Report AMP and whether the AMR was valid for the site-specific conditions.

Note E indicates that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but credits a different AMP. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the credited AMP would manage the aging effect consistently with the GALL Report AMP and whether the AMR was valid for the site-specific conditions.

The staff audited and reviewed the information in the LRA. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material

presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs.

The staff reviewed the AMRs in LRA Tables 3.5.2-1 through 3.5.2-4 that reference notes A through D, in order to confirm that the applicant: (a) provided a brief description of the system, components, materials, and environments; (b) stated that the applicable aging effects were reviewed and evaluated in the GALL Report; and (c) identified those aging effects for the structures, structural components, and component supports that are subject to an AMR. On the basis of its audit and review, the staff determined that, for AMRs not requiring further evaluation, as identified in LRA Table 3.5.1, the applicant's references to the GALL Report are acceptable and no further staff review is required, with two (2) exceptions which are discussed below.

LRA Table 3.5.1, Item 3.5.1-52, Groups B2, and B4: sliding support bearings and sliding support surfaces, identifies "Loss of mechanical function due to corrosion, distortion, dirt, overload, fatigue due to vibratory and cyclic thermal loads" as the aging effect/mechanism. The applicant's entry under Discussion is "Loss of mechanical function due to the listed mechanisms is not an aging effect. Such failures typically result from inadequate design or operating events rather than from the effects of aging. Failures due to cyclic thermal loads are rare for structural supports due to their relatively low temperatures."

During the on-site audit and review, the staff questioned the applicant as to whether Group B2 and B4 supports that have a mechanical function, in addition to a structural support function, are included in the applicant's Structures Monitoring Program, and are inspected for signs of any type of degradation. The applicant indicated this is the case. Although the applicant does not consider the loss of mechanical function due to the listed mechanisms to be an aging effect for these items, the applicant has an AMP which monitors for this aging effect/component combination. On the basis that the applicant has an acceptable program in place to manage loss of mechanical and structural support functions for Group B2 and B4 supports, the staff determined that this combination will be adequately managed during the period of extended operation.

LRA Table 3.5.1, Item 3.5.1-54, Groups B1.1, B1.2, and B1.3: constant and variable load spring hangers; guides; stops, identifies "Loss of mechanical function due to corrosion, distortion, dirt, overload, fatigue due to vibratory and cyclic thermal loads" as the "Aging Effect/Mechanism." The applicant's entry under "Discussion" is "Loss of mechanical function due to the listed mechanisms is not an aging effect. Loss of mechanical function due to distortion, dirt, overload, fatigue due to vibratory and cyclic thermal loads is not an aging effect requiring management. Such failures typically result from inadequate design or events rather than the effects of aging. Loss of material due to corrosion, which could cause loss of mechanical function, is addressed under Item 3.5.1-53 for Groups B1.1, B1.2, and B1.3 support members."

The staff questioned the applicant as to whether the ISI-IWF Program manages loss of mechanical function due to corrosion, distortion, dirt, overload, fatigue due to vibratory and cyclic thermal loads, for Group B1.1, B1.2, and B1.3 ASME Code supports (Audit Item 250). In a letter dated December 18, 2007, the applicant stated that this is included in its ISI-IWF Program. Although the applicant does not consider the loss of mechanical function due to the listed mechanisms to be an aging effect for these items, the applicant has an AMP which monitors for this aging effect/component combination. On the basis that the applicant has an

acceptable program in place to manage loss of mechanical function for Group B1.1, B1.2, and B1.3 ASME Code supports, the staff determined that this combination will be adequately managed during the extended period of operation.

The staff reviewed the AMR results in LRA Tables 3.5.2-1 through 3.5.2-4 that reference Note E.

For certain entries, the staff found that the applicant had referenced the AMPs that are credited in the GALL Report (IWL, IWE, IWF). However, the applicant chose to identify its AMPs for IWL, IWE, and IWF as plant-specific, rather than consistent with the GALL Report. Consequently, wherever these AMPs are credited, the applicant referenced Note E. This is acceptable, on the basis that the staff's review concluded that the applicant's AMPs are consistent with the corresponding GALL AMPs. The staff's detailed evaluations of the applicant's AMPs corresponding to IWL, IWE, and IWF are documented in SER Sections 3.0.3.3.2 through 3.0.3.3.4.

For entries that address cracking of masonry wall components, the applicant credits its Fire Protection Program, in addition to its Masonry Wall Program (which is consistent with the GALL Report), for aging management. The staff confirmed that these AMPs inspect for cracking of masonry wall components. The staff finds the applicant's AMR results to be acceptable.

For those entries that cover loss of material for carbon steel crane components, GALL Volume 2 Item VII B-3 (A-07) and Table 1, Item 3.3.1-73 is referenced. The applicant credits either the Periodic Surveillance and Preventive Maintenance Program or the Structures Monitoring Program. The staff confirmed that these AMPs inspect for loss of material of carbon steel components. The staff finds the applicant's AMR results to be acceptable.

Multiple entries cover loss of material for concrete and steel components of water control structures and related bulk commodities, exposed to either a fluid environment or air, and credit the Structures Monitoring Program. As discussed in the GALL Report, for water control structures, an applicant may credit its Structures Monitoring Program, in lieu of the RG 1.127 AMP described in the GALL Report, provided all elements of the GALL RG 1.127 AMP are incorporated in the applicant's Structures Monitoring Program. Entergy has chosen this approach, and the staff has confirmed that the applicant's Structures Monitoring Program, as revised in response to Audit Item 88, incorporates the elements of the GALL RG 1.127 AMP. Therefore, the staff finds the applicant's AMR results to be acceptable. The staff's detailed evaluation of the applicant's Structures Monitoring Program is documented in SER Section 3.0.3.2.15.

One entry covers loss of material for carbon steel roof decking in an indoor air (uncontrolled) environment. The applicant references Table 1 Item 3.5.1-25, and credits the Fire Protection AMP. The applicant has also credited the Structures Monitoring AMP in a separate Table 2 entry. Although the GALL report identifies the Structures Monitoring Program as the acceptable AMP, structural commodities related to plant fire protection are typically inspected under either the Fire Protection AMP or the Fire Water System AMP. For the specific applications cited above, the staff considers these AMPs to be acceptable alternatives or adjuncts to the Structures Monitoring AMP.

Two entries cover loss of material of stainless steel liner plates and gate, in the refueling canal and the spent fuel pool. The applicant references Table 1, Item 3.5.1-46, and credits the Water Chemistry Control – Primary and Secondary Program and monitoring of spent fuel pool level per technical specifications (spent fuel pool only). The staff found that the applicant's AMR result is consistent with the GALL Report for loss of material, but noted that the corresponding GALL Table 1 item also covers stress corrosion cracking of stainless steel liners. In LRA Table 1, Item 3.5.1-46, the applicant stated that the temperature threshold (140 °F) for the occurrence of stress corrosion cracking is higher than the operating temperature of the IP2 and IP3 spent fuel pools. Consequently, stress corrosion cracking is not an applicable aging effect. The staff confirmed that the operating temperature is lower than 140 °F. Therefore, the staff finds that stress corrosion cracking in the spent fuel liner is not an applicable aging effect.

In LRA Table 3.5.2-3, for spent fuel pool liner plate and gate (IP2), the applicant included Note E which means that the AMR line item is consistent with the GALL Report, but a different AMP is credited. The spent fuel pool at IP2 is not equipped with leak chase channels. The GALL Report indicates that the appropriate AMP for spent fuel pool liners is Water Chemistry Program as well as monitoring the pool level and leakage from the leak chase channels in accordance with technical specifications. The staff noted that LRA Table 3.5.1, Item 3.5.1-46 states that aging of the fuel pool liners will be managed by the water chemistry program and monitoring of spent fuel pool water level in accordance with Technical Specifications and leakage from the leak chase channel. The staff observed that the table included, in part, the following discussion, "Monitoring spent fuel pool water level in accordance with Technical Specifications and monitoring leakage from the leak chase channels (Unit 3) will also continue during the period of extended operation."

The staff noted that the monitoring program for IP2 differs from that specified for IP3 and from that credited in the GALL Report. The IP3 and GALL Report programs involve monitoring leakage from the leak chase channels. By letter dated January 28, 2008, the staff issued RAI 3.5A.2-1, requesting the applicant to explain whether the spent fuel pool water level may be insensitive to leakage comparable to the rate of evaporation and could be masked by routine makeup water additions. If spent fuel pool leakage could be masked by evaporation and routine water additions, the applicant was requested to describe how the proposed monitoring at IP2 would provide acceptable indication of a degrading liner or describe an alternative monitoring method (e.g., monitoring of nearby wells).

In its response to RAI 3.5A.2-1, dated February 27, 2008, the applicant stated that unlike the IP3 spent fuel pool, the IP2 spent fuel pool does not have leak chase channels. Therefore, no monitoring of leak chase channels can be performed for IP2. The monitoring of the spent fuel pool water level is credited along with the "Water Chemistry Control - Primary and Secondary Program" for managing the effects of aging on the IP2 spent fuel pool liner. The applicant added that routine makeup water additions to compensate for evaporative losses could mask leakage rates that are comparable to the rate of evaporation. However, leakage rates that could challenge the intended function of the spent fuel pool to maintain adequate inventory would be indicated by abnormal rates of level decrease and associated abnormal makeup requirements. In addition, the "Water Chemistry Control - Primary and Secondary Program" is an existing program that manages aging effects caused by corrosion and cracking mechanisms, which are potential causes of leakage. The applicant further stated that the program relies on monitoring and control of reactor water chemistry based on the EPRI guidelines in TR-105714, Rev. 5, Pressurized Water Reactor Primary Water Chemistry Guidelines, and TR-102134, Rev. 6,

Pressurized Water Reactor Secondary Chemistry Guidelines. The applicant stated that the effectiveness of the "Water Chemistry Control – Primary and Secondary Program" at managing degradation of stainless steel in a borated water environment has been demonstrated in industry and IP operating experience. The applicant stated that the IP2 operating experience did include leaks that were not due to the effects of aging. The applicant stated that the cause of these leaks was poor workmanship during initial construction of the liner and the identified defects due to the initial poor workmanship have been repaired. In a later conference call, held August 27, 2008, in relation to Audit Question 360, the applicant stated that during a rerack in the early 1990s, damage occurred to the liner which caused a pin-hole leak. This pin-hole damage to the liner was subsequently repaired. In its response to RAI 3.5A.2-1, the applicant stated that monitoring wells in proximity to the IP2 spent fuel pool are used for continued monitoring to identify any potential recurrence of leaks.

The applicant is relying on monitoring at IP2 of water chemistry and spent fuel pool water level to provide indication of a degrading liner. However, due to the lack of a leak-chase channel and collection system at IP2 to monitor, detect and quantify leakage through the SFP liner and preclude its long-term accumulation behind the liner in a reliable manner during the period of extended operation, the staff finds that the effectiveness of Water Chemistry AMP in controlling liner degradation is more difficult to confirm. The applicant stated it was using monitoring wells in proximity to the IP2 spent fuel pool to identify potential leaks (Commitment 25). However, the staff had concerns about the effectiveness of the applicant's AMP to detect and manage the effects of potential leakage through the IP2 spent fuel pool liner during the period of extended operation. The staff's further evaluation and resolution of this issue is discussed in the resolution of Open Item 3.0.3.2.15-2 (Audit Item 360) in SER Section 3.0.3.2.15.

The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing aging effects. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are indeed consistent. Therefore, the staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.1.1 AMR Results Identified as Not Applicable

LRA Table 3.5.1 Line Items 5, 8, 11, 13, 19, 20, 21, and 49 are identified as "Not Applicable" because they apply only to BWR containments. The staff confirmed that the applicant identified the correct items as being not applicable for this reason. The following additional items, discussed in SER Sections 3.5.2.1.2 thru 3.5.2.1.5, were also identified as not applicable by the applicant. The staff confirmed the applicant's conclusions.

LRA Table 3.5.1 Line Item 22 addresses prestressed containment tendons and anchorage components. The applicant stated that this line item does not apply to IP because neither the IP2 nor IP3 has a prestressed concrete containment. The IP containments are steel-lined, reinforced concrete. The staff confirmed the design of the containments based upon information in the IP2 and IP3 UFSARs. Therefore, the staff finds that this line item is not applicable to IP.

3.5.2.1.2 Tank Liners of Stainless Steel (LRA Table 3.5.1, Item 3.5.1-38)

There are no concrete or steel tanks with stainless steel liners within the scope of license renewal at IP.

3.5.2.1.3 Vibration Isolation Elements (LRA Table 3.5.1, Items 3.5.1-41 and 3.5.1-57)

There are no vibration isolation elements within the scope of license renewal at IP.

3.5.2.1.4 Earthen Water Control Structures (LRA Table 3.5.1, Item 3.5.1-48)

IP does not have earthen water control structures.

3.5.2.1.5 Group B1.1 High Strength Low-Alloy Bolts (LRA table 3.5.1, Item 3.5.1-51)

IP does not have high tensile strength bolting as defined by yield strength >150 ksi or low alloy steel bolts (SA 193 Grade B7) used for NSSS component supports.

The staff evaluated the applicant's claim that certain GALL Report items do not apply to Indian Point. The staff reviewed information from the UFSAR to confirm that the identified component types do not exist at Indian Point. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed do not apply, are not applicable.

3.5.2.2 AMR Results Consistent with the GALL Report for Which Further Evaluation is Recommended

In LRA Section 3.5.2.2, the applicant further evaluates aging management, as recommended by the GALL Report, for the structure and component support components and provides information concerning how it will manage aging effects in the following three areas:

(1) PWR and BWR containments:

- aging of inaccessible concrete areas
- cracks and distortion due to increased stress levels from settlement; reduction of foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundations if not covered by the Structures Monitoring Program
- reduction of strength and modulus of concrete structures due to elevated temperature
- loss of material due to general, pitting, and crevice corrosion
- loss of prestress due to relaxation, shrinkage, creep, and elevated temperature
- cumulative fatigue damage
- cracking due to SCC
- cracking due to cyclic loading

- loss of material (scaling, cracking, and spalling) due to freeze-thaw
- cracking due to expansion and reaction with aggregate and increase in porosity and permeability due to leaching of calcium hydroxide

(2) safety-related and other structures and component supports:

- aging of structures not covered by the Structures Monitoring Program
- aging management of inaccessible areas
- reduction of strength and modulus of concrete structures due to elevated temperature
- aging management of inaccessible areas for Group 6 structures
- cracking due to SCC and loss of material due to pitting and crevice corrosion
- aging of supports not covered by the Structures Monitoring Program
- cumulative fatigue damage due to cyclic loading

(3) QA for aging management of nonsafety-related components

For component groups evaluated in the GALL Report, for which the applicant claimed consistency with the report and for which the report recommends further evaluation, the staff audited and reviewed the applicant's evaluation to determine whether it adequately addressed the issues further evaluated. The staff reviewed the applicant's further evaluations against the criteria contained in SRP-LR Section 3.5.2.2.The staff's review of the applicant's further evaluation follows.

3.5.2.2.1 Containment Structures

The staff reviewed LRA Section 3.5.2.2.1 against the criteria in SRP-LR Section 3.5.2.2.1.

<u>Aging of Inaccessible Concrete Areas</u>. The staff reviewed LRA Section 3.5.2.2.1.1 using the review procedures of SRP-LR Section 3.5.3.2.1.1. The inaccessible areas in IP2 and IP3 containment structures are primarily the below grade areas of the structures.

In LRA Section 3.5.2.2.1.1, the applicant stated that concrete in accessible and inaccessible areas is in accordance with American Concrete Institute (ACI) specification ACI 318, "Building Code Requirements for Reinforced Concrete," for low permeability and resistance to aggressive chemical attack because of the following requirements:

- high cement content
- low water-to-cement ratio
- proper curing
- adequate air entrainment

The applicant stated that IP concrete also meets the requirements of the later ACI 201.2R-77, "Guide to Durable Concrete," as both specifications use the same ASTM standards for concrete

selection, application, and testing. The below-grade environment is not aggressive (pH > 5.5, chlorides < 500 ppm, and sulfates < 1,500 ppm). According to the applicant concrete air content was at least the required minimum of between 4 and 6 percent and water-to-cement ratios were in accordance with the ACI 318 version for IP construction, which allows a ratio of up to 0.576 (for non air-entrained concrete) for concrete with the compressive strength specified for IP. The applicant also stated that although specified water-to-cement ratios fall outside the established range of 0.35 to 0.45 of the GALL Report, IP concrete meets ACI specifications for acceptable concrete quality. The applicant concluded that an increase in porosity and permeability, cracking, and loss of material (spalling, scaling) due to aggressive chemical attack and cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel are not applicable for concrete in inaccessible areas. The applicant credited the Containment Inservice Inspection and Structures Monitoring programs to confirm the absence of concrete aging effects.

SRP-LR Section 3.5.3.2.1.1 states that the GALL Report recommends further evaluation of programs to manage aging effects in inaccessible areas of concrete if the environment is aggressive. Possible aging effects are increases in porosity and permeability, cracking and loss of material (spalling, scaling) due to aggressive chemical attack and cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel in PWR and BWR concrete and steel containments. The current aging management program for concrete containments is Section XI Subsection IWL examinations, in accordance with the requirements of 10 CFR 50.55a. However, Subsection IWL exempts from examination portions of the concrete containments that are inaccessible (e.g., foundation, exterior walls below grades, concrete covered by liner).

For the inaccessible areas, 10 CFR 50.55a(b)(2)(ix) requires that the applicant evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. In addition, the GALL Report recommends further evaluation to manage these aging effects for inaccessible areas if the below-grade environment is aggressive. Periodic monitoring of below-grade water chemistry (including consideration of potential seasonal variations) is an acceptable approach to demonstrate that the below-grade environment is aggressive or non-aggressive. The GALL Report recommends that examination of representative samples of below-grade concrete, when excavated for any reason, be performed.

The staff noted a discrepancy in the applicant's description of the containment concrete properties in LRA Section 3.5.2.2.1.1 which references ACI 318 for the concrete mix design. The staff confirmed that the 1963 edition of ACI 318 is the code of record for IP2 and IP3, and the design compressive strength of concrete is 3000 psi. The discrepancy was that the applicant referenced an inconsistent combination of air entrainment and water-cement ratio corresponding to its design compressive strength. Per Table 502(a) of ACI 318-63, for 3000 psi concrete, the water-cement ratio may be as high as 0.576 if there is no air entrainment. With air entrainment of four to six percent, as identified in LRA Section 3.5.2.2.1.1, the maximum water-cement ratio should be 0.465. Since the applicant claimed that the relevant aging effects of inaccessible concrete areas are not applicable because the IPEC concrete meets specifications and quality standards of ACI 318-63 and ACI 201.2R-77, in a telephone conference call dated September 3, 2008, the staff asked the applicant to clarify if the correct value should be 0.465, and also to describe how its concrete mix meets ACI 318-63 specifications. By letter dated November 6, 2008, the applicant stated that ACI 318-63 provides two methods for

determination of concrete properties which will result in the required concrete strength. The applicant stated that IP used method 2, which involves testing concrete trial mixes to establish a water-cement ratio that provides the required quality. The applicant further stated that the concrete mixture at IP was established based on tests of concrete mixtures and actual tests for containment concrete showed compressive strengths above the required 3000 psi. At the time of issuance of the SER with Open Items, the staff was in the process of reviewing the applicant's response. Thus, this issue was identified as Open Item 3.5-1.

The staff also noted that the applicant states in the LRA that the concrete meets the requirements of later ACI guide ACI 201.2R-77 since both documents use the same ASTM standards for selection, application and testing of concrete. During the phone call of September 3, 2008, the staff asked the applicant to clarify the use of the later ACI 201.2R-77 since the editions of the ASTM standards may have changed between 1963 and 1977. In its letter dated November 6, 2008, the applicant stated that IP structures designed in accordance with ACI 318-63 align with many of the recommendations in ACI 201.2R-77. As mentioned above, the staff was in the process of reviewing the applicant's response when the SER with Open Items was issued. Therefore, this issue was identified as part of Open Item 3.5-1.

The staff reviewed the applicant's response dated November 6, 2008, and determined that the staff required additional clarifications related to satisfaction of the GALL Report criteria for establishing concrete durability, and the applicant's claim that there are no applicable concrete aging effects requiring management.

In an effort to resolve this open item, the staff issued follow-up RAI 4: Open Item 3.5-1, dated April 3, 2009, which requested the following information:

a. In the clarification to LRA Section 3.5.2.2 (Part 1) on page 6 of Attachment 1 to letter NL-08-169, the applicant stated that it used Method 2 of Section 502 of ACI 318-63 by testing trial mixes to determine the water-cement ratios for the concrete mix design of the IP containments and other structures. In order for the staff to evaluate the quality and durability of concrete in IP structures that may be subject to degradation during the period of extended operation, the staff requests the applicant to define the water-cement ratio that was used at the time of construction. Additionally, to assist the staff in understanding the parameters related to concrete strength and durability during the period of extended operation, the applicant is requested to describe the methodology used to establish the required concrete compressive strength of 3000 psi for the containment and other safety-related concrete structures, in accordance with ACI 318- 63, Method 2. The applicant is requested to provide a summary of the results of statistical analyses performed, if any, of the original concrete strength tests, including number of samples, raw strength values from the test, the mean, the standard deviation, and the original criterion (e.g., mean minus 1 standard deviation, coefficient of variation) used to confirm that the required compressive strength was achieved. The applicant is requested to provide this information for the IP containments and other safety-related IP Unit 2 and 3 concrete structures, including the refueling cavities and the spent fuel pools, to support the applicant's view that IP

concrete meets the requirements of Method 2 in Section 502 of ACI 318-63 and the intent of ACI 201.2R-77.

b. If the applicant is unable to provide the information requested in part (a) above, the applicant is requested to explain how the aging effects on concrete will be adequately managed and safety margins will be determined during the period of extended operation.

By letter dated May 1, 2009, Entergy responded to follow-up RAI 4: Open Item 3.5-1 stating that:

> Pour data samples taken during construction show water-to-cement ratio used at IPEC ranged from a low of 0.488 (equipment hatch area) to a high-of 0.611 (containment el. 68') with an average ratio at the time of construction of 0.534. The method used to confirm the required concrete compressive strength of 3000 psi for the containment and other safety-related concrete structures, in accordance with ACI 318-63, Method 2 is testing of actual field samples taken during construction. ACI documents state that strength and durability are primarily governed by water-to-cement (w/c) ratio, and strength goes hand-in-hand with durability. The strength and durability are both based on the permeability of the concrete which is based on the distance between the cement particles, i.e., the closer the cement particles the stronger the concrete. Permeability is therefore a function of the w/c ratio, particle size distribution (PSD), type of cement, type of aggregate, compaction and quality control. Relying on just one indicator for durability is not justified, which is why the ACI code uses it only as a first estimate based on the tables for determining strength and durability. The ACI documents recommend that the strength based on w/c ratio should be verified by trial batches to ensure the specified properties of the concrete are met. To confirm that the required compressive strength was achieved, ACI 214.3R-88, "Simplified Version of the Recommended Practice for Evaluation of Strength Test Results of Concrete" was used to develop a summary of the results of the original concrete strength tests. These results are based on raw strength values from the test samples to obtain the mean and the standard deviation.
>
> IPEC containment and other safety-related structures were designed for a minimum compressive strength of 3000 psi. A total pour of approximately 20,000 cubic yards was expected. Therefore, in order to ensure this design parameter was achieved, an average design margin of 15% above this minimum was also specified.
>
> Approximately 200 concrete test reports for concrete used in IP containment, refueling cavity and spent fuel pool area were reviewed. Air entrainment values ranged between 3.5 and 6.5%. Only a few of the test reports indicated air entrainment higher than 6.0%. Those values are acceptable based on the ACI 211.1-77 section 5.3.3 which shows that higher entrainment values up to 7% are acceptable for extreme exposure conditions; higher air entrainment is generally better for durability. A primary concern for high air entrainment is an accompanying reduction in concrete strength. As discussed in the following

paragraph, the concrete used for IP containment, refueling cavity and spent fuel pool still exceeded the concrete design strength requirements in accordance with ACI 318-63 producing durable, low permeability concrete.

Each concrete test report involved an average of 3 sample concrete cylinders for strength testing. No test cylinder strength under 3000 psi 28-day strength was observed. The compressive strength from these samples ranged from a low of 3436 psi (containment exterior wall el. 68'-73') to 5393 psi (containment ring area) with an extreme of 6410 psi (containment equipment hatch area). The standard deviation obtained from the samples reviewed was determined to be approximately 670 psi with an average or mean concrete compressive strength of approximately 4050 psi. Based on this actual concrete test data, the required concrete compressive strength of 3000 psi for the containment and other safety-related concrete structures, in accordance with ACI 318-63, Method 2 was achieved with no sample below one standard deviation from the mean. Although this identifies that IPEC concrete is of good quality, the credited programs in Appendix B of the application will confirm the absence of significant concrete aging effects.

The applicant further stated that no response is required to part (b) of RAI 4, because the information requested in part (a) was provided.

The staff reviewed the applicant's response to follow-up RAI 4: Open Item 3.5-1 dated May 1, 2009, and found that the average, minimum, and maximum strength of concrete used in the IP containments, refueling cavities and spent fuel pools at 28 days was 4050, 3436, and 5393 psi respectively. This is based on a sample of 200 tests performed on concrete samples collected during construction of IP. The design of the IP containments and other safety-related structures is based on a minimum compressive strength of 3000 psi at 28 days.

Based on the test results, the staff concludes that there is a sufficient documented basis to provide reasonable assurance that IP concrete meets the ACI standards for strength. Inasmuch as the applicant has demonstrated that the compressive strength of the concrete exceeds the required strength of 3000 psi, the staff's previous concern with respect to the water-cement ratio is resolved. The staff concludes that the periodic inspections conducted under the Containment ISI - IWL Program and the Structures Monitoring Program will manage the aging of the IP concrete as required by 10 CFR 54.21(a)(3). Therefore, Open Item 3.5-1 is closed.

The staff noted that the applicant's "Further Evaluation" discussion in LRA 3.5.2.2.1.1 does not identify any commitments to monitor inaccessible areas. In response to a series of questions asked by the staff during the onsite audit and review, the applicant confirmed that its IWL inspection program is in accordance with the regulatory requirements in 10 CFR 50.55a, and includes provision to evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. The applicant also made the following two new license renewal commitments related to inaccessible concrete areas.

(1) The applicant has committed to a groundwater monitoring program that is sufficient in scope to assess the aggressiveness of the site groundwater to concrete on a periodic basis, as an enhancement of its Structures Monitoring AMP. (Commitment 25 in Regulatory Commitment

List, Revision 5; Attachment 4 to Entergy letter dated August 14, 2008)

(2) The applicant has committed to inspect inaccessible concrete areas that are exposed by excavation for any reason, as an enhancement of its Structures Monitoring AMP. (Commitment 25 in Regulatory Commitment List, Revision 5; Attachment 4 to Entergy letter dated August 14, 2008)

Based on the programs and commitments identified above, the staff finds that the LRA section is consistent with the GALL Report and the recommendations in the SRP-LR and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Cracks and Distortion Due to Increased Stress Levels from Settlement; Reduction of Foundation Strength, Cracking, and Differential Settlement Due to Erosion of Porous Concrete Subfoundations, if Not Covered by the Structures Monitoring Program</u>. The staff reviewed LRA Section 3.5.2.2.1.2 using the review procedures of SRP-LR Section 3.5.3.2.1.2.

In LRA Section 3.5.2.2.1.2, the applicant stated that these aging effects are not applicable because (a) IP does not rely on a dewatering system for control of settlement, (b) structures are founded on bedrock, (c) IN 97-11 does not include IP in plants susceptible to porous concrete containment subfoundation erosion, and (d) the IP containment foundation does not use porous concrete.

SRP-LR Section 3.5.3.2.1.2 states that the GALL Report recommends aging management of (1) cracks and distortion due to increases in component stress level from settlement for PWR and BWR concrete and steel containments and (2) reduction of foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundations for all types of PWR and BWR containments if not within the scope of structures monitoring program. Also, if a de-watering system is relied upon for control of settlement and erosion, then proper functioning of the de-watering system should be monitored for the period of extended operation.

The applicant stated that the aging effects due to settlement are not expected at IP for the containment building foundation. The containment building is founded on bedrock which would prevent significant settlement. In addition, there is no porous concrete subfoundation below the containment building of concern. Through review of the LRA and bases documents, the staff determined that the cracking and distortion due to increased stress levels from settlement; reduction of foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundations are not applicable to IP.

On the basis that IP has no relevant aging effects, the staff concludes that these aging effects are not applicable.

<u>Reduction of Strength and Modulus of Concrete Structures Due to Elevated Temperature</u>. The staff reviewed LRA Section 3.5.2.2.1.3 using the review procedures of SRP-LR Section 3.5.3.2.1.3.

In LRA Section 3.5.2.2.1.3, the applicant stated that ACI 349 specifies long-term temperature limits of 150 °F for general areas and 200 °F for local areas. The effects of aging due to elevated temperature exposure are not significant below these temperatures.

The applicant also stated that the IP2 containment areas during normal operation are below 130 °F bulk average temperature. Penetrations through the containment cylinder wall for pipes carrying hot fluid are cooled by air-to-air heat exchangers and the pipes are insulated to maintain the temperature in the adjoining concrete below 250 °F. The GALL Report provides for local area concrete temperatures higher than 200 °F if tests or calculations evaluate the reduction in strength. The applicant also states that an evaluation of IP2 hot piping penetration concrete has found temperatures up to 250 °F acceptable.

The applicant further stated that the IP3 containment areas normally operate below a bulk average temperature of 130 °F. Penetrations through the containment cylinder wall for pipes carrying hot fluid are cooled by air-to-air heat exchangers and the pipes are insulated to maintain the temperature in the adjoining concrete below 200 °F.

The applicant concluded that there are no aging effects due to elevated temperature requiring management for the IP containment structures.

SRP-LR Section 3.5.3.2.1.3 states that the GALL Report recommends further evaluation of programs to manage reduction of strength and modulus of concrete structures due to elevated temperature for PWR and BWR concrete and steel containments. The GALL Report notes that the implementation of ASME Section XI, Subsection IWL examinations and 10 CFR 50.55a would not be able to detect the reduction of concrete strength and modulus due to elevated temperature and also notes that no mandated aging management exists for managing this aging effect. The GALL Report recommends that a plant-specific evaluation be performed if any portion of the concrete containment components exceeds specified temperature limits, i.e., general temperature greater than 66 °C (150 °F) and local area temperature greater than 93 °C (200 °F).

Since the concrete temperature limits in the GALL report are not exceeded for IP3, the staff finds that the reduction of strength and modulus due to elevated temperature are not aging effects requiring management for IP3.

The staff's review of operating experience did not identify any occurrences of concrete degradation at the IP2 hot penetrations. However, because concrete degradation at elevated temperatures is a slow process, there is a need to confirm that an additional 20 years of operation will not lead to significant degradation. As stated above, the GALL Report recommends that a plant-specific evaluation be performed if any portion of the concrete containment components exceeds specified temperature limits. During a teleconference call held on September 3, 2008, the staff asked the applicant what the effects on the concrete properties (strength, modulus of elasticity) will be during the period of extended operation for areas where the local temperature exceeds 93 °C (200 °F). By letter dated November 6, 2008, the applicant stated that an engineering evaluation of the effect of 250 °F temperatures on the hot piping penetration concrete was performed. The evaluation determined that a reduction in strength of 15% could be expected from the elevated temperatures. The applicant further stated that this reduction in strength was acceptable since the original concrete compressive strength tests showed an actual strength more than 15 percent higher than the design strength

of 3000 psi. The applicant did not state how it addressed the reduction in modulus of elasticity and its effect in the evaluation. At the time of issuance of the SER with Open Items, the staff was in the process of reviewing the applicant's response; therefore, this issue was identified as Open Item 3.5-2.

The staff reviewed the applicant's response dated November 6, 2008, and concluded that the staff required additional clarifications before it could determine that the effects of elevated temperature on the IP2 containment structure had been adequately evaluated.

In an effort to resolve this open item, the staff issued follow-up RAI 5: Open Item 3.5-2, dated April 3, 2009, which requested the following information:

a. Clearly explain the role of the air-to-air heat exchangers in cooling the concrete around the hot piping penetrations. Include the normal operating temperature of the concrete as well as the maximum concrete temperature assuming failure of the heat exchangers.

b. In the clarification to LRA Section 3.5.2.2 (Part 3) on page 7 of Attachment 1 to letter NL-08-169, the applicant stated that a 15% reduction of concrete strength could be expected when reaching temperatures of 250 °F and that concrete compressive strength tests showed an actual strength more than 15% higher than design strength. Please provide the methodology used to arrive at the conclusion that the actual concrete strength is more than 15% greater than 3000 psi, (i.e., greater than 3450 psi). Provide a summary of the results, including number of samples, raw strength values from the test, the mean, the standard deviation, and the original criterion (e.g., mean minus 1 standard deviation) used to confirm that the claimed strength was achieved. Explain how consideration was given to the reduction in modulus of elasticity in the high temperature concrete evaluation.

c. If the applicant is unable to provide the information requested above, the applicant is requested to explain how the aging effects on concrete, due to high temperatures, will be adequately managed during the period of extended operation.

By letter dated May 1, 2009, Entergy responded to follow-up RAI 5: Open Item 3.5-2, in which it stated:

a. The air-to-air heat exchangers are discussed in IPEC 2 & 3 UFSAR Section 5.1.4.2.2 and Section 5.1.4 respectively. The function of the hot penetration cooling (HPC) system is to provide a cooling medium that will limit the temperature of the containment concrete surrounding a thermally hot penetrating line. Operating procedures require the system to be placed in service whenever RCS temperature is > 150 °F.

   The HPC system comprises two separate and non-interconnected subsystems. Each subsystem is composed of 2 positive displacement blowers, valves, air-to-air heat exchangers and connecting piping. Each

of the subsystems blowers supplies air from outside the building to the air-to-air heat exchanger which cools the space between the process line insulation and the penetration sleeve. The air-to-air heat exchanger is made by welding together one flat sheet on one embossed sheet of 10-gauge carbon steel. The embossment forms the coolant channels, through which the HPC system air passes. The unit is rolled into the form of a cylinder with an outside diameter of the penetration sleeve and inside diameter that allows placement over the outside of the pipe insulation [The applicant referred to Figures 8 and 9 in the response]. A typical hot penetration detail is shown in IP2 and IP3 UFSAR Fig 5.1-30 and 5.1-12 respectively.

There is one subsystem with two blowers for the main steam and feedwater penetrations, and one subsystem with two blowers for the hot penetrations in the radiological controlled area. Only one blower is needed in each subsystem. In the event that the operating blower stops, an alarm is initiated signaling to put the other one in service and initiate corrective actions.

Specific system pressure values have been established, which may indicate a possible obstruction, such as a clogged filter or debris in the system. The operators make daily rounds and would initiate corrective actions if unacceptable pressure values are observed. Corrective actions may include replacement of filters, belts or silencers and blowing out of the heat exchangers, if necessary.

System reliability was assessed by a review of IPEC operating experience over the past nine years of operation of the HPC system. The review identified no instances of loss of cooling which resulted in excess temperatures on concrete. This review identified that four IP2 and nine IP3 condition reports had been initiated. There were none that identified the cause as hot temperature on concrete. Ten were initiated due to vibrations and belt noise and three were due to increased motor temperature.

Temperatures taken in 1994 around the IP2 main steam penetrations over a period of eleven months during normal operations indicate that concrete was exposed to a range of temperatures from a low of 109 °F to a high of about 200 °F with the highest temperature occurring during the summer months. Based upon design and actual operating experience, recommendations of the NUREG-1801 (GALL) for concrete temperature are satisfied.

Analyses have been performed to characterize the concrete temperature response in the very unlikely event of system failure. To evaluate this scenario, IPEC performed a transient heat transfer analysis of containment hot piping penetrations. The results of the analysis indicated that in the improbable case that all cooling air would be lost to these penetrations, the surrounding concrete temperature at the hottest

penetration (main steam piping) would increase by about 80 °F in approximately 100 hours. It is highly improbable that cooling air would be lost for as much as 100 hours since the failure of any of the air blower drive motors is alarmed in the control room and operator daily walk downs would identify system deficiencies. Even if the adjoining concrete did reach temperatures of 250-300 °F, the strength of the structure would not be impaired for the following reasons:

1) No credit was taken for the tensile strength of the concrete around the penetrations.

2) These temperatures have substantially no effect on the strength of the penetration sleeve or the reinforcing bar in the area of the penetration.

b. The method used to arrive at the conclusion that the actual concrete strength is at least 15% greater than 3000 psi, (i.e., greater than 3450 psi) is review of actual concrete test results. The results of concrete samples taken and tested during construction in accordance with the requirements of ACI provide assurance that the minimum design strength of 3000 psi was achieved. Actual test results show that the containment shell and internal concrete had an average compressive strength of 4050 psi as indicated in response to Follow-up RAI 4: Open Item 3.5-1. No reduction in modulus of elasticity is expected for short term exposure of concrete to temperatures at or below 250 °F. Consideration of high temperatures effects on the modulus of elasticity was evaluated during the high temperature concrete evaluation. A review of information gathered from industry literature on effects of temperature concluded that concrete does not experience a significant reduction in elastic modulus due to exposure to temperatures less than 300 °F. Based on this data, no reduction in strength or modulus of elasticity was determined in the evaluation.

The applicant further stated that no response is required to part (c) of RAI 5, because the information requested in parts (a) and (b) was provided.

The staff determined that it does not agree with the applicant's assertion that reduction in modulus of elasticity of concrete would not occur at temperatures below 300 °F (*A Review of Concrete Properties for Prestressed Concrete Pressure Vessels*, R.K. Nanstad, ORNL/TM-5497, Oak Ridge National Laboratory, October 1976). However, the staff' has concluded that Open Item 3.5-2 issue resolved for the following reasons. The staff reviewed the applicant's response dated May 1, 2009, and noted that the concrete around IP2 containment hot penetrations has been exposed to a maximum temperature of about 200 °F during the 30 plus years of operation. GALL Report Item II.A1-1 does not require further evaluation if the temperature in local areas does not exceed 200 °F during normal operation or any other long-term period. In addition, past ASME IWL visual examinations of the areas around hot penetrations have not indicated any concrete degradation. Based on the design and operation of the hot penetration cooling system, there is reasonable assurance that IP2 containment concrete around hot penetrations will be maintained below the GALL Report 200 °F limit. Therefore, the staff concludes that the applicant will adequately manage the effects of aging for

IP containment concrete elements in accordance with 10 CFR 54.21(a)(3). On this basis, Open Item 3.5-2 is closed.

Loss of Material Due to General, Pitting and Crevice Corrosion. The staff reviewed LRA Section 3.5.2.2.1.4 using the review procedures of SRP-LR Section 3.5.3.2.1.4.

In LRA Section 3.5.2.2.1.4, the applicant stated that IP containment building concrete is in accordance with specification ACI 318, "Building Code Requirements for Reinforced Concrete," and meets requirements of the later ACI 201.2R-77 because both specifications use the same ASTM standards for concrete selection, application, and testing. Spills (*e.g.*, borated water spill) are cleaned up in a timely manner. The Structures Monitoring Program monitors interior concrete for cracks. The Containment Inservice Inspection Program (CII-IWE) inspects the steel liner plate and moisture barrier where the steel liner becomes embedded in the concrete floor. The applicant also stated that to prevent corrosion of the lower portion of the liner plate, the interior and exterior surfaces are protected from contact with the atmosphere by complete concrete encasement. Assuming a crack in the concrete, ground water cannot reach the liner plate because the concrete at this location is more than five feet thick and poured in multiple horizontal planes. Therefore, corrosion of the liner plate is not expected.

SRP-LR Section 3.5.3.2.1.4 states that the GALL Report identifies programs to manage loss of material due to general, pitting and crevice corrosion in accessible and inaccessible areas of the steel elements in drywell and torus or the steel liner and integral attachments for all types of PWR and BWR containments. The aging management program consists of ASME Section XI, Subsection IWE, and 10 CFR Part 50 Appendix J leak rate tests. Subsection IWE exempts from examination those portions of the containments that are inaccessible, such as embedded or inaccessible portions of steel liners and steel elements in drywell and torus, and integral attachments.

To cover the inaccessible areas, 10 CFR 50.55a(b)(2)(ix) requires that the applicant shall evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. In addition, the GALL Report recommends further evaluation of plant-specific programs to manage the aging effects for inaccessible areas if specific recommendations defined in the GALL Report cannot be satisfied.

The staff asked the applicant to perform a ten element comparison of its Containment Inservice Inspection AMP to GALL Report AMPs XI.S1 and XI.S2 (Audit Item 26). In a letter dated December 18, 2007, the applicant provided a comparison which confirmed that its IWE inspection program is in accordance with the regulatory requirements of 10 CFR 50.55a, and includes provisions to evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas.

Review of plant operating experience identified documentation of an occurrence of mild corrosion of the IP2 liner plate at the juncture with the concrete floor slab. This area is normally inaccessible, because it is covered by thermal insulation. The applicant removed thermal insulation to conduct an investigation of the degradation; no significant degradation was uncovered. The staff's evaluation of the Containment Inservice Inspection Program is documented in SER Section 3.0.3.3.2.

The staff finds that the LRA is consistent with the GALL Report and that the applicant has demonstrated that, the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Loss of Prestress Due to Relaxation, Shrinkage, Creep, and Elevated Temperature. The staff reviewed LRA Section 3.5.2.2.1.5 using the review procedures of SRP-LR Section 3.5.3.2.1.4.

In LRA Section 3.5.2.2.1.5, the applicant stated that loss of prestress forces due to relaxation, shrinkage, creep, and elevated temperature is not applicable because there are no prestressed tendons for the containment building structures. The IP containment structures are constructed of reinforced concrete.

Because IP does not have prestressed containments, the staff finds that this aging effect does not apply.

Cumulative Fatigue Damage. The staff reviewed LRA Section 3.5.2.2.1.6 using the review procedures of SRP-LR Section 3.5.3.2.1.6.

In LRA Section 3.5.2.2.1.6, the applicant stated that TLAAs are evaluated in accordance with 10 CFR 54.21(c) as documented in (LRA) Section 4. Fatigue TLAAs for containment steel liner and associated penetrations are evaluated as documented in (LRA) Section 4.6. The only associated TLAA involves the liner plate at the penetration for feedwater line #22 on IP2. A fatigue analysis does not exist for the other penetration components. The applicant also stated that the GALL Report BWR components, i.e., suppression pool shell and unbraced downcomers, are not applicable to the IP containments.

SRP-LR Section 3.5.3.2.1.6 states fatigue analyses included in CLB for the containment liner plate and penetrations are TLAAs as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c).

The staff's review of the applicant's containment liner plate TLAA is documented in SER Section 4.6.

Cracking Due to Stress Corrosion Cracking. The staff reviewed LRA Section 3.5.2.2.1.7 using the review procedures of SRP-LR Section 3.5.3.2.1.7.

In LRA Section 3.5.2.2.1.7, the applicant stated that the GALL Report recommends further evaluation of inspection methods to detect cracking due to SCC since visual VT-3 examinations may be unable to detect this aging effect. Potentially susceptible components at IP are penetration sleeves and bellows. The applicant also stated that stress corrosion cracking (SCC) is an aging mechanism that requires the simultaneous action of an aggressive chemical environment, sustained tensile stress, and a susceptible material. Elimination of any one of these elements will eliminate susceptibility to SCC. Stainless steel elements of containment, including dissimilar welds, are not susceptible to SCC because these elements are not subject to an aggressive chemical environment. The applicant further stated that a review of plant operating experience did not identify cracking of these components.

SRP-LR Section 3.5.3.2.1.7 states that the GALL Report recommends further evaluation of programs to manage cracking due to SCC for stainless steel penetration sleeves, dissimilar metal welds and penetration bellows in all types of PWR and BWR containments and BWR vent headers, vent line bellows, and downcomers. Transgranular stress corrosion cracking (TGSCC) is a concern for dissimilar metal welds. In the case of bellows assemblies, SCC may cause aging effects particularly if the material is not shielded from a corrosive environment. Containment ISI IWE and leak rate testing may not be sufficient to detect cracks, especially for dissimilar metal welds. Additional appropriate examinations to detect SCC in bellows assemblies and dissimilar metal welds are recommended to address this issue.

The staff concurs with the applicant's assessment that all three (3) elements – stress level, susceptible material, and corrosive environment – are needed for initiation of SCC. The staff's review of IP2 and IP3 operating experience did not identify any occurrences of cracking due to SCC for these components. On this basis, the staff finds the applicant's further evaluation to be acceptable. No augmented inspection is necessary. In addition, the staff finds that because IP2 and IP3 are PWRs, they do not have BWR vent headers, vent line bellows, and downcomers.

The staff finds that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Cracking Due to Cyclic Loading. The staff reviewed LRA Section 3.5.2.2.1.8 using the review procedures of SRP-LR Section 3.5.3.2.1.8.

In LRA Section 3.5.2.2.1.8, the applicant stated that this subsection lists containment components that require aging management for cracking due to cyclic loading because their original design bases did not include fatigue analyses. Specifically, containment mechanical penetrations, penetration sleeves, and dissimilar metal welds require aging management for cracking due to cyclic loading. The applicant stated that these components are designed to stress levels without requiring fatigue analyses; fine cracks are unlikely to occur. The applicant further stated that the existing requirements for leak rate testing per the Containment Leak Rate Program, and surface inspection per the Containment In-Service Inspection (CII-IWE) Program are adequate to detect cracking due to cyclic loading.

SRP-LR Section 3.5.3.2.1.8 states that the GALL Report recommends further evaluation of programs to manage cracking due to cyclic loading of steel and stainless steel penetration bellows and dissimilar metal welds in all types of PWR and BWR containments and BWR suppression pool shell and downcomers. Containment ISI IWE and leak rate testing may not be sufficient to detect fine cracks, especially for penetration bellows. VT-3 visual examination may not detect fine cracks.

In response to a staff question posed during the onsite audit and review, the applicant indicated that there has been no history of cracking in penetration bellows and dissimilar metal welds at IP. Since the number of thermal cycles is relatively low for containment penetrations and design basis calculations implicitly consider cyclic stress in the selection of the allowable stress limit, the staff finds that the applicant's assessment that IWE inspections and containment leak rate

testing will be adequate to detect cracking due to cyclic loading during the extended period of operation.

The staff finds that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Loss of Material (Scaling, Cracking, and Spalling) Due to Freeze-Thaw. The staff reviewed LRA Section 3.5.2.2.1.9 using the review procedures of SRP-LR Section 3.5.3.2.1.9.

In LRA Section 3.5.2.2.1.9, the applicant stated that IP inaccessible and accessible concrete areas are designed in accordance with ACI 318, "Building Code Requirements for Reinforced Concrete," which results in low permeability and resistance to aggressive chemical solutions by requiring the following.

- high cement content
- low water-to-cement ratio
- proper curing
- adequate air entrainment

The applicant stated that IP concrete also meets requirements of later ACI guide ACI 201.2R-77, "Guide to Durable Concrete," since both documents use the same American Society for Testing and Material (ASTM) standards for selection, application and testing of concrete. Therefore, according to the applicant, loss of material (scaling, cracking and spalling) due to freeze-thaw is not applicable for concrete in inaccessible areas. The absence of concrete aging effects is confirmed under the Containment Inservice Inspection (CII–IWL) and Structures Monitoring Program.

SRP-LR Section 3.5.3.2.1.9 states:

> The GALL Report recommends further evaluation of programs to manage loss of material (scaling, cracking, and spalling) due to freeze-thaw for concrete elements of PWR and BWR containments. Containment ISI Subsection IWL may not be sufficient for plants located in moderate to severe weathering conditions. Evaluation is needed for plants that are located in moderate to severe weathering conditions (weathering index >100 day-inch/yr) (NUREG-1557, Ref. 7). Documented evidence confirms that where the existing concrete had air content of 3 percent to 6 percent, subsequent inspections did not exhibit degradation related to freeze-thaw. Such inspections should be considered a part of the evaluation. The weathering index for the continental US is shown in ASTM C33-90, Fig. 1. The reviewer reviews and confirms that the applicant has satisfied the recommendations for inaccessible concrete as identified in the GALL Report. Otherwise, the reviewer reviews the applicant's proposed aging management program to verify that, where appropriate, an effective inspection program has been developed and implemented to ensure that these aging effects in inaccessible areas for plants located in moderate to severe weathering conditions are adequately managed.

The staff notes that Indian Point is located in a severe weathering region according to ASTM C33-90, Fig. 1. The applicant stated that concrete air content was at least the required minimum of between 4 and 6 percent and water-to-cement ratios were in accordance with the ACI 318-63 for IP construction, which allows a maximum water-cement ratio of up to 0.576 for concrete with the compressive strength specified for IP concrete structures. As discussed above, the applicant later revised its discussion of the water-cement ratio and air entrainment, and provided a supplemental discussion based on tests showing that the concrete exceeds the plant's 3000 psi minimum design strength. Inspections have indicated spalling on the containment cylindrical wall, which the applicant attributed to a Cadweld concrete coverage issue and not to the freeze-thaw aging mechanism. Further discussion with regard to the spalling and concrete mix properties was the subject of Open Item 3.0.3.3.2-1 and Open Item 3.5-1, respectively. Information regarding the closure of these open items is provided in SER Sections 3.0.3.3.2 and 3.5.2.2.

As discussed in the resolution of Open Item 3.0.3.3.2-1, the identified cylindrical wall concrete spalls are at locations where the reinforcing bars were spliced using Cadweld sleeves and there was insufficient concrete coverage. IWL inspections in 2005 and 2009 using enhanced visual aids have shown little, if any, additional degradation since the original detection in 2000. In the resolution of Open Item 3.5-1, the applicant provided information on the strength of in-place concrete which demonstrated that the concrete was above the 3000 psi design minimum strength required for the plant at the time of construction.

During its review, the staff noted that none of the containment spalling was attributed by the applicant to freeze-thaw, and the staff's review did not identify any spalling that was attributed to freeze-thaw. The lack of identified freeze-thaw degradation in accessible regions provides assurance that freeze-thaw degradation has not occurred in inaccessible areas. Additionally, since freeze-thaw degradation has not occurred in the first 30 years of plant operation, it is unlikely to occur in the future. However, if conditions exist in accessible areas that could indicate the presence of or result in degradation in inaccessible areas, i.e., if freeze-thaw degradation is or was identified in accessible areas, the applicant would be required to evaluate the inaccessible areas in accordance with 10 CFR 50.55a(b)(2)(viii)(E). Further, the staff notes that the GALL Report, Volume II, specifically identifies ASME Section XI, Subsection IWL, as an acceptable AMP for managing this aging effect for accessible concrete containment structures. Therefore, since the applicant is committed to IWL inspections for the extended period of operation, and containment concrete degradation has not been attributed to freeze-thaw, the staff concludes that the applicant's approach with respect to accessible areas is consistent with the GALL Report.

With regard to inaccessible areas, the applicant has identified its Structures Monitoring Program to manage the aging effects on concrete. In addition, the applicant has made the following license renewal commitment, as enhancements to the Structures Monitoring Program (Reference: Commitment 25 in the List of Regulatory Commitments, Revision 5, in Attachment 4 to Entergy's letter dated August 14, 2008):

(1) Inspect inaccessible concrete areas in environments where observed conditions in accessible areas exposed to the same environment indicate that significant concrete degradation is occurring

(2) Inspect inaccessible concrete areas that are exposed by excavation for any reason.

Based on the programs and commitments identified above, the staff finds that the applicant has identified adequate programs to manage the effects of aging for both accessible and inaccessible concrete; further, the staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Cracking Due to Expansion and Reaction with Aggregate, and Increase in Porosity and Permeability Due to Leaching of Calcium Hydroxide. The staff reviewed LRA Section 3.5.2.2.1.10 using the review procedures of SRP-LR Section 3.5.3.2.1.10.

In LRA Section 3.5.2.2.1.10, the applicant stated that in accordance with the GALL Report, aging management is not required because IP containment concrete (walls, dome, basemat and ring girder) is designed in accordance with specification ACI 318, Building Code Requirements for Reinforced Concrete, and concrete specification requires that the potential reactivity of aggregates be tested in accordance with ASTM C 289 and ASTM C 227. Also ASTM C 295 shall be used to identify elements in the aggregate which may be unfavorably reactive with alkalis in cement. The applicant states that concrete structures are not exposed to flowing water and the concrete used was constructed in accordance with the recommendations in ACI 201.2R-77 for durability. Therefore, according to the applicant, reaction with aggregates and increase in porosity and permeability due to leaching of calcium hydroxide is not an applicable aging mechanism for IP concrete structures. The applicant further stated that the absence of concrete aging effects is confirmed under the Containment Inservice Inspection (CII– IWL) and Structures Monitoring Programs.

SRP-LR Section 3.5.3.2.1.10 states that the GALL Report recommends further evaluation of programs to manage cracking due to expansion and reaction with aggregate, and increase in porosity and permeability due to leaching of calcium hydroxide in concrete elements of PWR and BWR concrete and steel containments. The GALL Report recommends containment ISI Subsection IWL to manage these aging effects. An aging management program is not necessary, even if reinforced concrete is exposed to flowing water, if there is documented evidence that confirms the in-place concrete was constructed in accordance with the recommendations in ACI 201.2R-77.

The staff notes that the GALL Report, Volume II, specifically identifies ASME Section XI, Subsection IWL, as an acceptable AMP for managing these aging effects for concrete containment structures. Although the applicant considers this aging mechanism is not an applicable mechanism for IP concrete structures, the applicant has an AMP which monitors for this aging effect/component combination. Since the applicant is committed to managing the aging effects through IWL inspections for the extended period of operation, the applicant's approach is consistent with the GALL Report.

The staff finds that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.2.2 Safety-Related and Other Structures and Component Supports

The staff reviewed LRA Section 3.5.2.2.2 against the criteria in SRP-LR Section 3.5.3.2.2.

Aging of Structures Not Covered by Structures Monitoring Program. The staff reviewed LRA Section 3.5.2.2.2.1 using the review procedures of SRP-LR Section 3.5.3.2.2.1.

In LRA Section 3.5.2.2.2.1, the applicant stated that IP concrete structures subject to aging management review, except for containment concrete covered by Containment Inservice Inspection Program (CII– IWL), are included in the Structures Monitoring Program and supplemented by other aging management programs as appropriate. The applicant states this is true for concrete items even if the aging management review did not identify aging effects requiring management. Aging effects discussed below for structural steel items are also addressed by the Structures Monitoring Program. The applicant's additional discussion of specific aging effects follows:

(1) Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling) Due to Corrosion of Embedded Steel for Groups 1-5, 7, 9 Structures

    The aging mechanisms associated with cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel are applicable only to below-grade concrete/grout structures. The below-grade environment for IP is not aggressive and concrete is designed in accordance with specification ACI 318, "Building Code Requirements for Reinforced Concrete," which results in low permeability and resistance to aggressive chemical solutions by providing a high cement, low water/cement ratio, proper curing and adequate air content (between 4% and 6%). Water-cement ratios were in accordance with requirements of the version of ACI 318 used in IP construction, which allows a ratio of up to 0.576 for concrete with the compressive strength specified for IP concrete. Although specified water-cement ratios fall outside the established range of 0.35 to 0.45 provided in the guidance of the GALL Report, IP concrete meets the specifications of ACI to ensure acceptable quality concrete is obtained.

    Therefore, cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel are not aging effects requiring management for IP Groups 1-5, 7, 9 structures.

(2) Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling) Due to Aggressive Chemical Attack for Groups 1-5, 7, 9 Structures

    Aggressive chemical attack becomes significant to concrete exposed to an aggressive environment. Resistance to mild acid attack is enhanced by using a dense concrete with low permeability and a low water-to-cement ratio. These groups of structures at IP use a dense low-permeable concrete with a water-to-cement ratio that met the ACI 318 requirements, which provides an acceptable degree of protection against aggressive chemical attack. Water chemical analysis results confirm that the site groundwater is non-aggressive. IP concrete is constructed in accordance with the recommendations in ACI 201.2R-77 for durability.

IP below-grade environment is not aggressive. Therefore, increase in porosity and permeability cracking, loss of material (spalling, scaling) due to aggressive chemical attack are not aging effects requiring management for IP Groups 1-5, 7, 9 concrete structures.

(3) Loss of Material Due to Corrosion for Groups 1-5, 7, 8 Structures

IP Structures Monitoring Program and Containment Inservice Inspection (CII– IWE) for containment steel liner will be used to manage this aging effect for IP Groups 1-5, 7, 8 structures.

(4) Loss of Material (Spalling, Scaling) and Cracking Due to Freeze-Thaw for Groups 1-3, 5, 7-9 Structures

Aggregates were in accordance with specifications and materials conforming to ACI and ASTM standards. IP structures are constructed of a dense, durable mixture of sound coarse aggregate, fine aggregate, cement, water, and admixture. Water-cement ratios are within the limits provided in ACI 318 and air entrainment percentages are within the range prescribed in the GALL Report.

Therefore, loss of material (spalling, scaling) and cracking due to freeze thaw are not aging effects requiring management for IP Groups 1-3, 5, 7-9 structures.

(5) Cracking Due to Expansion and Reaction with Aggregates for Groups 1-5, 7-9 Structures

Aggregates were selected locally and were in accordance with specifications and materials conforming to ACI and ASTM standards at the time of construction, which are in accordance with the recommendations in ACI 201.2R-77 for concrete durability. IP structures are constructed of a dense, durable mixture of sound coarse aggregate, fine aggregate, cement, water, and admixture. Water-cement ratios are within the limits provided in ACI 318, and air entrainment percentages were within the range prescribed in the GALL Report. Therefore, cracking due to expansion and reaction with aggregates for Groups 1-5, 7-9 structures is not an aging effect requiring management.

(6) Cracks and Distortion Due to Increased Stress Levels from Settlement for Groups 1-3, 5-9 Structures

For Groups 1-3, 5-9 structures at IP, settlement is not credible since structures are founded on bedrock. Therefore, cracks and distortion due to increased stress levels from settlement for Groups 1-3, 5-9 structures is not an aging effect requiring management for IP concrete.

(7) Reduction in Foundation Strength, Cracking, Differential Settlement Due to Erosion of Porous Concrete Subfoundation for Groups 1-3, 5-9 Structures

IP concrete was provided in accordance with ACI 318 requirements resulting in dense, well-cured, high-strength concrete with low permeability, and a porous subfoundation is not provided. Structures are supported on bedrock, and erosion of the subfoundation is

not credible since the subfoundation bears directly against the bedrock and the possibility of loss of soil resulting in voids below the subgrade is not credible. Operating history has not identified settlement and therefore reduction in foundation strength, cracking, differential settlement due to erosion of porous concrete subfoundation are not aging effects requiring management for IP Groups 1-3, 5-9 structures.

(8) Lock Up Due to Wear for Lubrite® Radial Beam Seats in BWR Drywell and Other Sliding Support Surfaces

IP is a reinforced concrete containment and does not contain radial beam seats; therefore, lockup due to wear for this component is not applicable. IP does use Lubrite® plate in support applications inside containment; however, owing to the wear-resistant material used, the low frequency of movement, and the slow movement between sliding surfaces, lock-up due to wear is not an aging effect requiring management at IP. Nevertheless, Lubrite® plates are included within the Inservice Inspection (ISI-IWF) Program to confirm the absence of aging effects requiring management for these components.

SRP-LR Section 3.5.3.2.2.1 states that the GALL Report recommends further evaluation of certain structure-aging effect combinations not covered by structures monitoring programs, including (1) cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel for Groups 1-5, 7, and 9 structures, (2) increase in porosity and permeability, cracking, and loss of material (spalling, scaling) due to aggressive chemical attack for Groups 1-5, 7, and 9 structures, (3) loss of material due to corrosion for Groups 1-5, 7, and 8 structures, (4) loss of material (spalling, scaling) and cracking due to freeze-thaw for Groups 1-3, 5, and 7-9 structures, (5) cracking due to expansion and reaction with aggregates for Groups 1-5 and 7-9 structures, (6) cracks and distortion due to increased stress levels from settlement for Groups 1-3 and 5-9 structures, and (7) reduction in foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundation for Groups 1-3 and 5-9 structures. The GALL Report recommends further evaluation only for structure-aging effect combinations not within structures monitoring programs. In addition, the GALL Report recommends further evaluation of structure/aging effect combination of lock-up due to wear of Group 4 Lubrite® components, if they are not covered by either the ASME Section XI, Subsection IWF or the structures monitoring program. The applicant's structures monitoring program confirms that the CLB is maintained through periodic testing and inspection of critical plant structures, systems, and components.

The staff's evaluation of the above structure-aging effect combinations is provided below.

(1) Cracking, Loss of Bond, and loss of Material (Spalling, Scaling) due to Corrosion of embedded steel for Group 1-5, 7,9 structures

Through review of the LRA and bases documents, the staff found that cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel for Groups 1-5, 7, and 9 will be monitored within the Structures Monitoring Program by the applicant. Although the applicant considers that this aging effect does not require management, the applicant has an AMP which monitors for this aging effect/structure combination. On the basis that the applicant has acceptable programs in place to

manage the aging effects, the staff determined that this combination will be adequately managed and no further evaluation is required.

(2) Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling) Due to Aggressive Chemical Attack for Groups 1-5, 7, and 9 Structures

Through review of the LRA and bases documents, the staff found that increase in porosity and permeability, cracking, and loss of material (spalling; scaling) due to aggressive chemical attack for Groups 1-5, 7, and 9 structures will be monitored within the Structures Monitoring Program by the applicant. Although the applicant considers that this aging effect does not require management, the applicant has an AMP which monitors for this aging effect/structure combination. On the basis that the applicant has acceptable programs in place to manage the aging effects, the staff determined that this combination will be adequately managed and no further evaluation is required.

(3) Loss of Material Due to Corrosion for Groups 1-5, 7, and 8 Structures

Through review of the LRA and the basis document the staff found that the loss of material due to corrosion for Groups 1-5, 7, and 8 structures is an aging effect which will be managed by the applicant's Structures Monitoring Program. On this basis, the staff finds the monitoring of the above characteristic acceptable.

(4) Loss of Material (Spalling, Scaling) and Cracking Due to Freeze-Thaw for Groups 1-3, 5, and 7-9 Structures

Through review of the LRA and the basis document the staff found that the loss of material (spalling, scaling) and cracking due to freeze-thaw for Groups 1-3, 5, and 7-9 structures will be monitored within the Structures Monitoring Program by the applicant. Although the applicant considers that this aging effect does not require management, the applicant has an AMP which monitors for this aging effect/structure combination. On the basis that the applicant has acceptable programs in place to manage the aging effect, the staff determined that this combination will be adequately managed and no further evaluation is required.

(5) Cracking Due to Expansion and Reaction with Aggregates for Groups 1-5 and 7-9

Through review of the LRA and the basis document the staff found that the cracking due to expansion and reaction with aggregates for Groups 1-5 and 7-9 structures will be monitored within the Structures Monitoring Program by the applicant. Although the applicant considers that this aging effect does not require management, the applicant has an AMP which monitors for this aging effect/structure combination. On the basis that the applicant has acceptable programs in place to manage the aging effects, the staff determined that this combination will be adequately managed and no further evaluation is required.

(6) Cracks and Distortion Due to Increased Stress Levels from Settlement for Groups 1-3 and 5-9 Structures

Through review of LRA and the basis document the staff found that cracks and distortion due to increased stress levels from settlement for Groups 1-3 and 5-9 structures is not a plausible aging effect at IP because of the nonexistence of this aging mechanism. The IP Class 1 structures are founded on sound bedrock or supported by steel pilings which prevent significant settlement. The staff finds the applicant's assessment that these aging effects are not applicable to IP Class I structures is acceptable. On the basis that IP does not have any components from this group, the staff found that this aging effect is not applicable to IP.

(7) Reduction in Foundation Strength, Cracking, and Differential Settlement Due to Erosion of Porous Concrete Subfoundation for Groups 1-3 and 5-9 Structures

Through review of the LRA and bases documents, the staff found that reduction in foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundation for Groups 1-3 and 5-9 structures are not plausible aging effects because of the nonexistence of these aging mechanisms. The applicant stated that the aging effects of reduction in foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundation for Groups 1-3 and 5-9 structures are not applicable to IP since there are no porous concrete subfoundations of concern below these structures. Due to the absence of porous concrete subfoundations, the staff finds these aging effects are not applicable to IP.

(8) Lockup Due to Wear for Lubrite® Radial Beam Seats in BWR Drywell and Other Sliding Support Surfaces.

Through review of the LRA, the staff found that the applicant has credited its Inservice Inspection (ISI–IWF) program to manage aging of Lubrite® and other sliding support surfaces. The staff finds the applicable AMP (IWF) acceptable for inspection of Lubrite® and other sliding support surfaces. The staff's evaluation of the ISI-IWF Program is contained in SER Section 3.0.3.3.4.

Based on the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.5.2.2.2.1 criteria. For those line items that apply to LRA Section 3.5.2.2.2.1, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Aging Management of Inaccessible Areas</u>. The staff reviewed LRA Section 3.5.2.2.2.2 using the review procedures of SRP-LR Section 3.5.3.2.2.2.

In LRA Section 3.5.2.2.2.2, the applicant stated that IP concrete for Group 1-3, 5 and 7-9 inaccessible concrete areas was provided in accordance with specification ACI 318, Building

Code Requirements for Reinforced Concrete, which requires the following, resulting in low permeability and resistance to aggressive chemical solution:

- high cement content
- low water permeability
- proper curing
- adequate air entrainment

The applicant states that IP concrete also meets requirements of later ACI guide ACI 201.2R-77, "Guide to Durable Concrete," since both documents use the same ASTM standards for selection, application and testing of concrete. Inspections of accessible concrete have not revealed degradation related to corrosion of embedded steel. IP below-grade environment is not aggressive as defined in the GALL Report. Therefore, according to the applicant, loss of material due to corrosion of embedded steel is not an aging effect requiring management for IP concrete.

SRP-LR Section 3.5.3.2.2.2 states:

(1) The GALL Report recommends further evaluation of programs to manage loss of material (spalling, scaling) and cracking due to freeze-thaw in below-grade inaccessible concrete areas of Groups 1-3, 5, and 7-9 structures. Structures monitoring program may not be sufficient for plants located in moderate to severe weathering conditions. Further evaluation is needed for plants that are located in moderate to severe weathering conditions (weathering index >100 day-inch/yr) (NUREG-1557). Documented evidence confirms that where the existing concrete had air content of 3% to 6% and water-to-cement ratio of 0.35-0.45, subsequent inspection did not exhibit degradation related to freeze-thaw. Such inspections should be considered a part of the evaluation. The weathering index for the continental U.S. is shown in ASTM C33-90, Fig. 1.

(2) The GALL Report recommends further evaluation of programs to manage cracking due to expansion and reaction with aggregate in below-grade inaccessible concrete areas of Groups 1-5 and 7-9 structures in below-grade inaccessible concrete areas of Groups 1-3, 5, and 7-9 structures. An aging management program is not necessary, if there is documented evidence that confirms the in-place concrete was constructed in accordance with the recommendations in ACI 201.2R-77.

(3) The GALL Report recommends further evaluation of programs to manage cracks and distortion due to increased stress levels from settlement, and reduction of foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundations could occur in below-grade inaccessible concrete areas of Groups 1-3, 5, and 7-9 structures. The initial licensing basis for some plants included a program to monitor settlement. If no settlement was evident during the first decade or so, the staff may have given the applicant approval to discontinue the program. However, if a de-watering system is relied upon for control of settlement and erosion, then the applicant is to ensure proper functioning of the de-watering system through the period of extended operation.

(4) The GALL Report recommends further evaluation of aging management for inaccessible concrete areas, such as foundation and exterior walls below grade exposed to an

aggressive environment. Possible aging effects are increases in porosity and permeability, cracking and loss of material (spalling, scaling) due to aggressive chemical attack, and cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel for Groups 1-3, 5, 7-9 structures. Periodic monitoring of below-grade water chemistry (including consideration of potential seasonal variations) is an acceptable approach to demonstrate that the below-grade environment is aggressive or non-aggressive. The GALL Report recommends that examination of representative samples of below-grade concrete, when excavated for any reason, be performed.

(5) The GALL Report recommends further evaluation of programs to manage increase in porosity and permeability due to leaching of calcium hydroxide in below-grade inaccessible concrete areas of Groups 1-3, 5, and 7-9 structures. An aging management program is not necessary, if there is documented evidence that confirms the in-place concrete was constructed in accordance with the recommendations in ACI 201.2R-77.

The staff's evaluation of the above structure-aging effect combinations is provided below.

The staff noted that the applicant's further evaluation discussion in LRA 3.5.2.2.2.2 does not identify any commitments to monitor inaccessible areas. In response to the staff's review, the applicant has made the following license renewal commitments related to inaccessible areas, as enhancements to the SMP (Reference: Commitment 25 in the List of Regulatory Commitments, Revision 5, in Attachment 4 to Entergy's letter dated August 14, 2008):

(1) Inspect inaccessible concrete areas in environments where observed conditions in accessible areas exposed to the same environment indicate that significant concrete degradation is occurring in such inaccessible areas, as part of its Structures Monitoring AMP

(2) Conduct a groundwater monitoring program that is sufficient in scope to assess the aggressiveness of the site groundwater to concrete on a periodic basis, as part of its Structures Monitoring AMP

(3) Inspect inaccessible concrete areas that are exposed by excavation for any reason, as part of its Structures Monitoring AMP

Based on the programs and commitments identified above, the staff determined that the applicant has an adequate program for monitoring all five structure-aging effect combinations mentioned above for inaccessible areas of containment concrete. Therefore, the staff finds that with satisfactory resolution of Open Item 3.5-1, the applicant's approach is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Reduction of Strength and Modulus of Concrete Structures Due to Elevated Temperature</u>. The staff reviewed LRA Section 3.5.2.2.2.3 using the review procedures of SRP-LR Section 3.5.3.2.2.3.

In LRA Section 3.5.2.2.2.3, the applicant stated that this aging effect is not applicable because during normal operation, bulk average temperature of Groups 1-5 concrete elements is below 150 °F and local temperatures remain below 200 °F. Group 1-5 concrete elements remain at temperatures below the thresholds for aging degradation due to elevated temperature.

SRP-LR Section 3.5.3.2.2.3 states that the GALL Report recommends a plant-specific evaluation be performed if any portion of the concrete Groups 1-5 structures exceeds specified temperature limits, i.e., general temperature greater than 66 °C (150 °F) and local area temperature greater than 93 °C (200 °F).

Based on the above, the staff concludes that reduction of strength and modulus of concrete structures due to elevated temperature is not applicable to Groups 1 through 5 structures at IP since the GALL Report temperature limits are not exceeded.

The staff finds that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Aging Management of Inaccessible Areas for Group 6 Structures</u>. The staff reviewed LRA Section 3.5.2.2.2.4 using the review procedures of SRP-LR Section 3.5.3.2.2.4.

In LRA Section 3.5.2.2.2.4, the applicant stated that, for inaccessible areas of certain Group 6 structures, aging effects are covered by inspections in accordance with the Structures Monitoring Program. The Structures Monitoring Program will include guidance to perform periodic engineering evaluations of groundwater samples to assess aggressiveness of groundwater to concrete. The applicant provided the following additional information:

1. Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)/Aggressive Chemical Attack; and Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)/Corrosion of Embedded Steel in Below-Grade Inaccessible Concrete Areas of Group 6 Structures

   Below-grade exterior reinforced concrete structures are subject to non aggressive environment (pH > 5.5, chlorides < 500 ppm, and sulfates < 1,500 ppm). Therefore, increase in porosity and permeability, cracking, loss of material (spalling, scaling)/ aggressive chemical attack; and cracking, loss of bond, and loss of material (spalling, scaling)/ corrosion of embedded steel are not aging effects requiring management for below-grade inaccessible concrete areas of IP Group 6 structures.

2. Loss of Material (Spalling, Scaling) and Cracking Due to Freeze-thaw in Below-Grade Inaccessible Concrete Areas of Group 6 Structures

   Aggregates were selected locally and were in accordance with specifications and materials conforming to ACI and ASTM standards at the time of construction. IP structures are constructed of a dense, durable mixture of sound coarse aggregate, fine aggregate, cement, water, and admixture. Water-cement ratios are within the limits provided in ACI 318, and air entrainment percentages were within the range prescribed

in the GALL Report. Therefore, loss of material (spalling, scaling) and cracking due to freeze thaw are not aging effects requiring management for IP Groups 6 structures.

3. Cracking Due to Expansion and Reaction with Aggregates, Increase in Porosity and Permeability, and Loss of Strength Due to Leaching of Calcium Hydroxide in Below-Grade Inaccessible Concrete Areas of Group 6 Structures

   Aggregates were selected locally and were in accordance with specifications and materials conforming to ACI and ASTM standards at the time of construction, which are in accordance with the recommendations in ACI 201.2R-77 for concrete durability. IP structures are constructed of a dense, durable mixture of sound coarse aggregate, fine aggregate, cement, water, and admixture. Water-cement ratios are within the limits provided in ACI 318-63, and air entrainment percentages were within the range prescribed in the GALL Report. IP below-grade environment is not aggressive (pH > 5.5, chlorides < 500 ppm, and sulfates < 1,500 ppm). Therefore, cracking due to expansion and reaction with aggregates, increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide in below-grade inaccessible concrete areas of Group 6 Structures is not an aging effect requiring management for IP concrete.

SRP-LR Section 3.5.3.2.2.4 states that the GALL Report recommends further evaluation for inaccessible areas of certain Group 6 structure/aging effect combinations as identified below, whether or not they are covered by inspections in accordance with the GALL Report, Chapter XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants," or the Federal Energy Regulatory Commission/US Army Corp of Engineers dam inspections and maintenance.

1. Increases in porosity and permeability, cracking and loss of material (spalling, scaling) due to aggressive chemical attack and cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel could occur in below-grade inaccessible concrete areas of Group 6 structures. Periodic monitoring of below-grade water chemistry (including consideration of potential seasonal variations) is an acceptable approach to demonstrate that the below-grade environment is aggressive or non-aggressive. The GALL Report recommends that examination of representative samples of below-grade concrete, when excavated for any reason, be performed, if the below-grade environment is aggressive.

2. Loss of material (spalling, scaling) and cracking due to freeze-thaw could occur in below-grade inaccessible concrete areas of Group 6 structures. Further evaluation is needed for plants that are located in moderate to severe weathering conditions (weathering index >100 day-inch/yr) (NUREG-1557, Ref. 7). Documented evidence confirms that where the existing concrete had air content of 3% to 6% and water-to-cement ratio of 0.35-0.45, subsequent inspection did not exhibit degradation related to freeze-thaw. Such inspections should be considered a part of the evaluation. The weathering index for the continental US is shown in ASTM C33-90, Fig. 1.

3. Cracking due to expansion and reaction with aggregate could occur in below-grade inaccessible concrete areas of Group 6 structures and increase in porosity and permeability due to leaching of calcium hydroxide could occur in below-grade inaccessible concrete areas of Group 6 structures. An aging management program is

not necessary, even if reinforced concrete is exposed to flowing water, if there is documented evidence that confirms the in-place concrete was constructed in accordance with the recommendations in ACI 201.2R-77.

The staff's evaluation of the above structure-aging effect combinations is given below.

The staff noted that the applicant's initial commitment to managing aging of inaccessible areas of Group 6 structures (water control structures) was insufficient because the Structures Monitoring AMP did not include specific provisions identified in GALL AMP XI.S7 "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants". The staff asked the applicant to describe how all the provisions of GALL AMP XI.S7 had been incorporated into its Structures Monitoring AMP (Audit Item 88). As a result of the staff's inquiries, the applicant made the following additional license renewal commitments to enhance the Structures Monitoring AMP (Reference: Commitment 25 in the List of Regulatory Commitments, Revision 5, in Attachment 4 to Entergy's letter dated August 14, 2008):

(1) Perform inspection of normally submerged concrete portions of the intake structures at least once every five years.

    The applicant had also made commitments to enhance the Structures Monitoring AMP, for managing aging of inaccessible areas for all structures groups.

(2) Conduct a groundwater monitoring program that is sufficient in scope to assess the aggressiveness of the site groundwater to concrete on a periodic basis.

(3) Conduct inspection of inaccessible concrete areas that are exposed by excavation for any reason.

(4) Inspect inaccessible concrete areas in environments where observed conditions in accessible areas exposed to the same environment indicate that significant concrete degradation is occurring in such inaccessible areas.

The staff's review of operating experience identified the existence of concrete degradation of water control structures. Spalling of concrete and rusting of rebar has occurred at a number of locations. The staff's evaluation of these conditions is in Section 3.0.3.2.15 of this SER.

Although the applicant considers that the above mentioned aging effects do not require management, its Structures Monitoring Program with the above commitments monitors for these aging effect/structure combinations. Based on the programs and commitments identified above, the staff finds that the LRA is consistent with the GALL Report for the three structure aging effect combinations, and the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Cracking Due to Stress Corrosion Cracking and Loss of Material Due to Pitting and Crevice Corrosion</u>. The staff reviewed LRA Section 3.5.2.2.2.5 using the review procedures of SRP-LR Section 3.5.3.2.2.5.

In LRA Section 3.5.2.2.2.5, the applicant addressed cracking due to SCC and loss of material due to pitting and crevice corrosion in stainless steel tank liners, by stating that this aging effect is not applicable because there are no concrete or steel tanks with stainless steel liners within the scope of license renewal.

In SRP-LR Section 3.5.3.2.2.5, it states that the GALL Report recommends further evaluation of plant-specific programs to manage cracking due to SCC and loss of material due to pitting and crevice corrosion for stainless steel tank liners exposed to standing water.

On the basis that there are no stainless steel tank liners within the scope of license renewal, the staff concludes that the SRP-LR criterion is not applicable, and further evaluation is not required.

Aging of Supports Not Covered by the Structures Monitoring Program. The staff reviewed LRA Section 3.5.2.2.2.6 using the review procedures of SRP-LR Section 3.5.3.2.2.6.

In LRA Section 3.5.2.2.2.6, the applicant stated that the GALL Report recommends further evaluation of certain component support/aging effect combinations if they are not covered by the applicant's structures monitoring program. Component supports at IP are included in the Structures Monitoring Program for Groups B2 through B5 and the Inservice Inspection (ISI-IWF) program for Group B1. The applicant provided the following additional information:

(1) Reduction in concrete anchor capacity due to degradation of the surrounding concrete for Groups B1 through B5 supports:

IP concrete anchors and surrounding concrete are included in the Structures Monitoring Program (Groups B2 through B5) and Inservice Inspection (ISI-IWF) Program (Group B1).

Item 3.5.1-40 of LRA Table 3.5.1 addresses building concrete at locations of expansion and grouted anchors for the aging effect of reduction in concrete anchor capacity due to local concrete degradation/service-induced cracking or other concrete aging mechanisms. The GALL Report recommends the Structures Monitoring Program for monitoring this concrete component for the stated aging effect. The staff finds that the applicant has appropriately credited the SMP for Groups B2 through B5 component supports and surrounding concrete consistent with the GALL Report. However, for the Group B1 (ASME Class 1, 2, 3 & MC) supports, the applicant's statement that "IP concrete anchors and surrounding concrete" implies that the applicant is crediting the ISI-IWF AMP for both the supports and surrounding concrete. The staff found that, while ISI-IWF is appropriate for the Group B1 component supports themselves, ISI-IWF is not specifically applicable for concrete surrounding the anchors for these supports, because of the code support boundary definition which extends to the surface of the building but does not include the building structure. Therefore, the applicant was requested to confirm which AMP it is using to manage the effects of aging for the concrete surrounding the B1 supports. This was identified as Open Item 3.5-3.

In its response to Open Item 3.5-3 in Attachment 1, dated January 27, 2009, the applicant stated that, as indicated in the discussion column for Item 3.5.1-40 of LRA Table 3.5.1, the applicable aging management program for concrete surrounding concrete anchors is the Structures Monitoring Program. The applicant stated that the evaluation provided in LRA Section 3.5.2.2.2.6 (1), reproduced as the first paragraph under Item (1) above of the SER, is clarified to read as follows: "Concrete surrounding IPEC concrete anchors is included in the Structures Monitoring Program (Groups B1 through B5)."

The staff finds the above response to Open Item 3.5-3 acceptable since the applicant clarified and revised its evaluation in LRA Section 3.5.2.2.2.6 (1) to confirm that the aging management program for building concrete and grout pads at locations surrounding anchors and base plates of Groups B1 through B5 supports is the Structures Monitoring Program, which makes it consistent with the GALL Report. Therefore, the issue raised in Open Item 3.5-3 is closed.

(2) Loss of material due to general and pitting corrosion, for Groups B2 through B5 supports:

Loss of material due to corrosion of steel support components is an aging effect requiring management at IP. The Structures Monitoring Program manages this aging effect. For components subject to loss of material due to boric acid corrosion, the Boric Acid Corrosion Prevention Program manages this aging effect.

One entry covers loss of material for carbon steel fire damper framing in an indoor air (uncontrolled) environment. The applicant references Table 1 Item 3.5.1-39, and credits the Fire Protection Program. One entry covers loss of material for carbon steel fire hose reels in an indoor air (uncontrolled) environment. The applicant references Table 1 Item 3.5.1-39, and credits the Fire Water System Program. The applicant references Table 1 Item 3.5.1-25, and credits the Fire Protection Program. The applicant has also credited the Structures Monitoring Program in a separate Table 2 entry. Although the GALL Report identifies the Structures Monitoring Program as the acceptable AMP, structural commodities related to plant fire protection are typically inspected under either the Fire Protection AMP or the Fire Water System Program. For the specific applications cited above, the staff considers these AMPs to be acceptable alternatives or adjuncts to the Structures Monitoring Program. The staff's evaluation of these conditions is discussed in SER Sections 3.0.3.2.7 and 3.0.3.2.8.

(3) Reduction/loss of isolation function due to degradation of vibration isolation elements for Group B4 supports:

The IP aging management review did not identify any component support structure/aging effect combination corresponding to NUREG-1801 Volume 2 Item III.B4.2-a.

SRP-LR Section 3.5.3.2.2.1 states that the GALL Report recommends further evaluation of certain component support/aging effect combinations if they are not covered by the structures monitoring program. This includes (1) reduction in concrete anchor capacity due to degradation of the surrounding concrete, for Groups B1-B5 supports; (2) loss of material due to general and

pitting corrosion, for Groups B2-B5 supports; and (3) reduction/loss of isolation function due to degradation of vibration isolation elements, for Group B4 supports. Further evaluation is necessary only for structure/aging effect combinations not covered by the structures monitoring program.

The staff noted that Items (1) and (2) above are included in the scope of the applicant's Structures Monitoring Program, and Item (3) is not applicable. Since the combination is covered by the applicant's Structures Monitoring Program, as recommended by the SRP-LR, further evaluation is not necessary.

The staff finds that the LRA is consistent with the GALL Report, and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Cumulative Fatigue Damage Due to Cyclic Loading. LRA Section 3.5.2.2.2.7 states that TLAAs are evaluated in accordance with 10 CFR 54.21(c), as documented in (LRA) Section 4. During the process of identifying TLAAs in the IP current licensing basis, no fatigue analyses were identified for ASME component support members, anchor bolts, and welds.

Based on the above, the staff concludes that this further evaluation is not applicable, because no fatigue analyses exist in the current licensing basis for the ASME component support members, anchor bolts, or welds.

3.5.2.2.3 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 documents the staff's evaluation of the applicant's QA program.

3.5.2.3 AMR Results Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.5.2-1 through 3.5.2-4, the staff reviewed additional details of the AMR results for material, environment, AERM, and AMP combinations not consistent with or not addressed in the GALL Report.

In LRA Tables 3.5.2-1 through 3.5.2-4, the applicant indicated, via Notes F through J that the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report. The applicant provided further information about how it will manage the aging effects. Specifically, note F indicates that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR line item component, material, and environment combination is not evaluated in the GALL Report. Note I indicate that the aging effect identified in the GALL Report for the line item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

For component type, material, and environment combinations not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant has demonstrated that the effects of aging will be adequately managed so that the intended

functions will be maintained consistent with the CLB for the period of extended operation. The staff's evaluation is documented in the following sections.

3.5.2.3.1 Containment Building—Summary of Aging Management Review—LRA Table 3.5.2-1

The staff reviewed LRA Table 3.5.2-1, as amended by letter date June 11, 2008, which summarizes the results of AMR evaluations for the containment building component groups.

The applicant identified 38 unique component/material/environment/aging effect/AMP groups for the containment building. Twenty-seven have AMR results consistent with the GALL Report, as identified by reference to Notes A through E. The staff confirmed that the references to Table 1 and GALL Report Volume II line items are appropriate.

The applicant referenced Note F for nickel alloy bellows penetrations exposed to uncontrolled air-indoor (internal) with no aging effects and no aging management program required. This material has high corrosion resistance as discussed in "Metals Handbook, Desk Edition, 1985" and therefore no aging effects are expected and no AMP is required. Therefore, the staff finds the applicant's AMR results acceptable.

The applicant referenced Note I and plant-specific Note 501, which states "[t]he IP environment is not conducive to the listed aging effects. However, the identified AMP will be used to confirm the absence of significant aging effects for the period of extended operation." The applicant identified its Structures Monitoring Program, ISI-IWF, CII-IWL, or Fire Protection Program to manage the aging effects. The staff's review of the above programs is documented in SER Sections 3.0.3.2.15, 3.0.3.3.4, 3.0.3.3.2, and 3.0.3.2.7, respectively. The staff finds that the credited AMP is appropriate in each case. Since the applicant has committed to appropriate AMPs for the period of extended operation, the staff finds these AMR results to be acceptable.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.3.2 Water Control Structures—Summary of Aging Management Review—LRA Table 3.5.2-2

The staff reviewed LRA Table 3.5.2-2, which summarizes the results of AMR evaluations for the water control structures component groups. The staff confirmed that the references to Table 1 and GALL Report, Volume II line items are appropriate.

The applicant proposes to manage concrete material, aging effect none, by using the Structures Monitoring Program. The staff's review of the Structures Monitoring Program is documented in SER Section 3.0.3.2.15. These line items reference Note I and plant-specific Note 501, which states "[t]he IP environment is not conducive to the listed aging effects. However, the identified AMP will be used to confirm the absence of significant aging effects for the period of extended operation." Although the applicant considers that this aging effect does not exist at its plant, the applicant has an AMP which monitors for this aging effect/structure combination. On the basis that the applicant has committed to appropriate aging management

programs for the period of extended operation, the staff finds these AMR results to be acceptable.

By letter dated March 24, 2008, the applicant added baffling/grating partition and support platform for IP3 constructed of Fiberglass material exposed to a fluid environment. The applicant proposes to manage the loss of material aging effect for this component using the Structures Monitoring Program. This line item references Note J, which states that neither the component nor the material and environment combination is evaluated in NUREG-1801. The applicant has credited the Structures Monitoring Program to manage the loss of material aging effect in a fluid environment for materials such as concrete, carbon steel, stainless steel, copper alloy using Note E. Based on the rationale used in SER Section 3.5.2.1 for these materials with Note E subject to a fluid environment, the staff finds the AMP the applicant has proposed for the fiberglass material component is appropriate and acceptable.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.3.3 Turbine Building, Auxiliary Building, and Other Structures—Summary of Aging Management Review—LRA Table 3.5.2-3

The staff reviewed LRA Table 3.5.2-3, which summarizes the results of AMR evaluations for the turbine building, auxiliary building, and other structures component groups. The staff confirmed that the references to Table 1 and GALL Report, Volume II line items are appropriate.

The applicant proposes to manage concrete material, aging effect "none," by using the Structures Monitoring Program. The staff's review of the Structures Monitoring Program is documented in SER Section 3.0.3.2.15. These line items reference Note I and plant-specific Note 501, which states "[t]he IP environment is not conducive to the listed aging effects. However, the identified AMP will be used to confirm the absence of significant aging effects for the period of extended operation." Although the applicant considers that this aging effect does not exist at its plant, the applicant has an AMP which monitors for this aging effect/structure combination. Because the applicant has committed to the appropriate aging management program for the period of extended operation, the staff finds these AMR results to be acceptable.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.3.4 Bulk Commodities—Summary of Aging Management Review—LRA Table 3.5.2-4

The staff reviewed LRA Table 3.5.2-4, which summarizes the results of AMR evaluations for the bulk commodities component groups. The staff confirmed that the references to Table 1 and GALL Report, Volume II line items are appropriate.

The applicant proposes to manage concrete material, aging effect "none," by using the Structures Monitoring Program. The staff's review of the Structures Monitoring Program is documented in SER Section 3.0.3.2.15. These line items reference Note I and plant-specific Note 501, which states "The IP environment is not conducive to the listed aging effects. However, the identified AMP will be used to confirm the absence of significant aging effects for the period of extended operation." Although the applicant considers that this aging effect does not exist at its plant, the applicant has an AMP which monitors for this aging effect/structure combination. On the basis that the applicant has committed to appropriate aging management programs for the period of extended operation, the staff finds these AMR results to be acceptable.

The applicant references Note J, indicating that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report. The specific component/material/environment/aging effect/AMP groups referencing Note J are:

(1) Fire stops/cera blanket, mineral wool/air – indoor uncontrolled/cracking, de-lamination, separation/ Fire Protection

(2) Fire wrap/cerafiber, cera blanket/air – indoor uncontrolled/loss of material/ Fire Protection

(3) Insulation/fiberglass, calcium silicate/air – indoor uncontrolled/None/None

Plant-specific Note 502 is referenced, which states:

> Loss of insulating characteristics due to insulation degradation is not an aging effect requiring management for insulation material. Insulation products, which are made from fiberglass fiber, calcium silicate, stainless steel, and similar materials, in an air – indoor uncontrolled environment do not experience aging effects that would significantly degrade their ability to insulate as designed. A review of site operating experience identified no aging effects for insulation used at IP.

(4) Water stops/elastomers/air – indoor uncontrolled/None/None

The staff confirmed that groups (1) and (2) are within the scope of the applicant's Fire Protection Program. Since these components/materials serve the intended function of a fire barrier, the staff considers the Fire Protection AMP to be an appropriate and acceptable program for aging management of the listed aging effects. Therefore, the staff finds the applicant's AMR results acceptable. The staff's review of the Fire Protection Program is documented in SER Section 3.0.3.2.7.

For group (3), the staff concurs that deterioration of the insulation function in an indoor air environment is not expected. The staff questioned the applicant about any occurrences of moisture wetting the insulation (Audit Item 248). In its response, dated December 18, 2007, the applicant stated that there have been no occurrences, because the insulation is jacketed. Since the stated aging effect is not expected for insulation in an indoor environment and is also not

indicated in the applicant's operating experience, the staff finds the applicant's AMR results acceptable.

For group (4), the staff notes that water stops are completely embedded in concrete joints between walls and floors, to eliminate water leakage through the joints. They are inaccessible for inspection. The GALL Report does not recommend inspection of water stops.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the structures and component supports within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6 Aging Management of Electrical and Instrumentation and Controls System

This section of the SER documents the staff's review of the applicant's AMR results for the following electrical and instrumentation and control (I&C) system components and component groups:

- high-voltage insulators
- insulated cables and connections
- metal-enclosed bus
- switchyard bus and connections
- transmission conductors and connections
- direct burial 138-kilovolt (kV) insulated transmission cables

3.6.1 Summary of Technical Information in the Application

LRA Section 3.6 provides AMR results for the electrical and I&C system components and component groups. LRA Table 3.6.1, "Summary of Aging Management Programs for the Electrical and I&C Components Evaluated in Chapter VI of NUREG 1801," is a summary comparison of the applicant's AMRs with those evaluated in the GALL Report for the electrical and I&C system components and component groups.

The applicant's AMRs evaluated and incorporated applicable plant-specific and industry operating experience in the determination of AERMs. The plant-specific evaluation included condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.6.2 Staff Evaluation

The staff reviewed LRA Section 3.6 to determine whether the applicant provided sufficient information to demonstrate that the effects of aging, for the electrical and I&C system components within the scope of license renewal and subject to an AMR, will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff conducted an onsite audit of AMRs to verify the applicant's claim that certain AMRs are consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA is applicable and that the applicant identified the appropriate GALL Report AMRs. SER Section 3.0.3 documents the staff's evaluations of the AMPs. SER Section 3.6.2.1 documents the details of the staff's audit evaluation.

During the onsite audit, the staff also selected AMRs consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations are consistent with the SRP-LR Section 3.6.2.2 acceptance criteria. SER Section 3.6.2.2 documents the staff's audit evaluations.

The staff also conducted a technical review of the remaining AMRs not consistent with or not addressed in the GALL Report. The technical review evaluated whether all plausible aging effects have been identified and whether the aging effects listed are appropriate for the material-environment combinations specified. SER Section 3.6.2.3 documents the staff's evaluations.

For components that the applicant claimed are not applicable or require no aging management, the staff reviewed the AMR line items and the plant's operating experience to verify the applicant's claims.

Table 3.6-1 summarizes the staff's evaluation of components, aging effects or mechanisms, and AMPs listed in LRA Section 3.6 and addressed in the GALL Report.

Table 3.6-1 Staff Evaluation for Electrical and Instrumentation and Controls in the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Electrical equipment subject to 10 CFR 50.49 environmental qualification (EQ) requirements (3.6.1-1)	Degradation due to various aging mechanisms	Environmental Qualification of Electric Components	Yes	TLAA	Consistent with GALL Report (see Section 3.6.2.2.1)

OAGI0001368_00844

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Electrical cables, connections and fuse holders (insulation) not subject to 10 CFR 50.49 EQ requirements (3.6.1-2)	Reduced insulation resistance and electrical failure due to various physical, thermal, radiolytic, photolytic, and chemical mechanisms	Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements	No	Non-EQ Insulated Cables and Connections	Consistent with GALL Report (see Section 3.6.2.1)
Conductor insulation for electrical cables and connections used in instrumentation circuits not subject to 10 CFR 50.49 EQ requirements that are sensitive to reduction in conductor insulation resistance (3.6.1-3)	Reduced insulation resistance and electrical failure due to various physical, thermal, radiolytic, photolytic, and chemical mechanisms	Electrical Cables and Connections Used In Instrumentation Circuits Not Subject to 10 CFR 50.49 EQ Requirements	No	Non-EQ Instrumentation Circuit Test Review	Consistent with GALL Report (see Section 3.6.2.1)
Conductor insulation for inaccessible medium-voltage (2 kV to 35 kV) cables (e.g., installed in conduit or direct buried) not subject to 10 CFR 50.49 EQ requirements (3.6.1-4)	Localized damage and breakdown of insulation leading to electrical failure due to moisture intrusion, water trees	Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements	No	Non-EQ Inaccessible Medium-Voltage Cables	Consistent with GALL Report (see SER Section 3.6.2.1)
Connector contacts for electrical connectors exposed to borated water leakage (3.6.1-5)	Corrosion of connector contact surfaces due to intrusion of borated water	Boric Acid Corrosion	No	Boric Acid Corrosion Prevention	Consistent with GALL Report (see SER Section 3.6.2.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Fuse Holders (Not Part of a Larger Assembly): Fuse holders - metallic clamp (3.6.1-6)	Fatigue due to ohmic heating, thermal cycling, electrical transients, frequent manipulation, vibration, chemical contamination, corrosion, and oxidation	Fuse Holders	No	Not applicable	Not applicable (see SER Section 3.6.2.1.1)
Metal-enclosed bus—bus, connections (3.6.1-7)	Loosening of bolted connections due to thermal cycling and ohmic heating	Metal-Enclosed Bus	No	Metal-Enclosed Bus Inspection	Consistent with GALL Report (see SER Section 3.6.2.1)
Metal-enclosed bus—insulation, insulators (3.6.1-8)	Reduced insulation resistance and electrical failure due to various physical, thermal, radiolytic, photolytic, and chemical mechanisms	Metal-Enclosed Bus	No	Metal-Enclosed Bus Inspection	Consistent with GALL Report (see SER Section 3.6.2.1)
Metal-enclosed bus—enclosure assemblies (3.6.1-9)	Loss of material due to general corrosion	Structures Monitoring Program	No	Metal-Enclosed Bus Inspection	Consistent with GALL Report (see SER Section 3.6.2.1)
Metal enclosed bus - enclosure assemblies (3.6.1-10)	Hardening and loss of strength due to elastomers degradation	Structures Monitoring Program	No	Not applicable	Not consistent with GALL Report (see Section 3.6.2.3)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
High voltage insulators (3.6.1-11)	Degradation of insulation quality due to presence of any salt deposits and surface contamination; loss of material caused by mechanical wear due to wind blowing on transmission conductors	A plant-specific aging management program is to be evaluated	Yes	None	Consistent with GALL Report (see SER Section 3.6.2.2.2)
Transmission conductors and connections; switchyard bus and connections (3.6.1-12)	Loss of material due to wind induced abrasion and fatigue; loss of conductor strength due to corrosion; increased resistance of connection due to oxidation or loss of preload	A plant-specific aging management program is to be evaluated	Yes	None	Consistent with GALL Report (see SER Section 3.6.2.2.3)
Cable connections - metallic parts (3.6.1-13)	Loosening of bolted connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	No	Non-EQ Bolted Cable Connections	Consistent with GALL Report (see SER Section 3.6.2.1)
Fuse holders (Not Part of a Larger Assembly) - insulation material (3.6.1-14)	None	None	NA	Not Applicable	Consistent with GALL Report

The staff's review of the electrical and I&C system component groups followed one of the following approaches. In one approach, documented in SER Section 3.6.2.1, the staff reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and require no further evaluation. In the second approach, documented in SER Section 3.6.2.2,

the staff reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. In the third approach, documented in SER Section 3.6.2.3, the staff reviewed AMR results for components that the applicant indicated are not consistent with, or not addressed in, the GALL Report. SER Section 3.0.3 documents the staff's review of AMPs credited to manage or monitor the aging effects of the electrical and I&C system components.

3.6.2.1 AMR Results Consistent with the GALL Report

In LRA Section 3.6.2.1, the applicant identified the materials, environments, AERMs, and the following programs that manage aging effects for the electrical and I&C system components:

- Boric Acid Corrosion Prevention Program
- Metal-Enclosed Bus Inspection Program
- Non-EQ Bolted Cable Connections Program
- Non-EQ Inaccessible Medium-Voltage Cable Program
- Non-EQ Instrumentation Circuits Test Review Program
- Non-EQ Insulated Cables and Connections Program

LRA Table 3.6.2-1 summarizes the results of AMRs for the electrical and I&C system components and indicates the AMRs claimed to be consistent with the GALL Report.

For component groups evaluated in the GALL Report, for which the applicant claimed consistency with the report, where the report does not recommend further evaluation, the staff's audit and review determined whether the GALL Report evaluation bounds the plant-specific components of these GALL Report component groups.

For each AMR line item, the applicant stated how the information in the tables aligns with the information in the GALL Report. Notes A through E indicate how the AMR is consistent with the GALL Report. The staff audited these AMRs.

Note A indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the GALL Report AMP. The staff audited these line items to verify consistency with the GALL Report and validity of the AMR for the site-specific conditions.

Note B indicates that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the GALL Report AMP. The staff audited these line items to verify consistency with the GALL Report and verified that the identified exceptions to the GALL Report AMPs have been reviewed and accepted. The staff also determined whether the applicant's AMP is consistent with the GALL Report AMP and whether the AMR is valid for the site-specific conditions.

Note C indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the GALL Report AMP. This note indicates that the applicant was unable to find a listing of some system components in the GALL Report; however, the applicant identified in the GALL Report a different component with the same material, environment, aging

effect, and AMP as the component under review. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component is applicable to the component under review and whether the AMR is valid for the site-specific conditions.

Note D indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the GALL Report AMP. The staff audited these line items to verify consistency with the GALL Report. The staff ascertained whether the AMR line item of the different component is applicable to the component under review and whether the identified exceptions to the GALL Report AMPs have been reviewed and accepted. The staff also determined whether the applicant's AMP is consistent with the GALL Report AMP and whether the AMR is valid for the site-specific conditions.

Note E indicates that the AMR line item is consistent with the GALL Report for material, environment, and aging effect but credits a different AMP. The staff audited these line items to verify their consistency with the GALL Report. The staff also determined whether the credited AMP would manage the aging effect consistently with the GALL Report AMP and whether the AMR is valid for the site-specific conditions.

The staff audited and reviewed the information in the LRA. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA is applicable and that the applicant identified the appropriate GALL Report AMRs. The staff's evaluation follows.

The staff reviewed LRA Table 3.6.1, which summarizes the results of AMR evaluations in Chapter VI of the GALL Report for the electrical and I&C component groups.

The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing aging effects. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are indeed consistent. Therefore, the staff concludes that the applicant has demonstrated that the effects of aging on these components will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.1.1 AMR Results Identified as Not Applicable

In the discussion column of LRA Table 3.6.1 for Item 3.6.1-6, the applicant stated that fatigue due to ohmic heating, thermal cycling, electrical transients, frequent manipulation, vibration, chemical contamination, corrosion, and oxidation of fuse holders (not part of a larger assembly)—metallic clamp is not applicable to IP because all fuse holders utilizing metallic clamps are either part of an active device or located in circuits that perform no function intended for license renewal. In accordance with 10 CFR 54.21(a)(1)(i), fuse holders installed in an active assembly are part of an active assembly and do not require an AMR. Therefore, the staff finds that fuse holders with metallic clamps at IP are not subject to AMR.

3.6.2.1.2 Loss of Material Due to General Corrosion

In the discussion section in Table 3.6.1, Item 3.6.1-9, of the LRA, the applicant stated that the Metal-Enclosed Bus Inspection Program will manage the effect of loss of material due to general corrosion through visual inspection. The staff noted that in the AMR results line that points to Table 3.6.1, Item 3.6.1-9, the applicant included a reference to Note E.

The staff reviewed the AMR results lines referenced to Note E and determined that the component type, material, environment, and aging effect are consistent with the corresponding lines of the GALL Report; however, where the GALL Report recommends the AMP XI.S6, "Structures Monitoring Program," the applicant has proposed the Metal-Enclosed Bus Inspection Program. As discussed in Section 3.0.3.1, the staff finds the Metal-Enclosed Bus Inspection Program acceptable to inspect loss of material due to general corrosion of the metal enclosed bus enclosure assemblies.

3.6.2.2 AMR Results Consistent with the GALL Report for Which Further Evaluation Is Recommended

In LRA Section 3.6.2.2, the applicant further evaluated aging management, as recommended by the GALL Report, for the electrical and I&C system components and provided information concerning how it will manage aging in the following areas:

- electrical equipment subject to EQ
- degradation of insulator quality due to salt deposits or surface contamination and loss of material due to mechanical wear
- loss of material due to wind-induced abrasion and fatigue, loss of conductor strength due to corrosion, and increased resistance of connection due to oxidation or loss of preload
- QA for aging management of nonsafety-related components

For component groups evaluated in the GALL Report, for which the applicant claimed consistency with the GALL Report and for which further evaluation is recommended, the staff audited and reviewed the applicant's evaluation to determine whether it adequately addresses the issues further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in SRP-LR Section 3.6.2.2. The staff's review of the applicant's further evaluations for those component groups follows.

3.6.2.2.1 Electrical Equipment Subject to Environmental Qualification

LRA Section 3.6.2.2.1 states that EQ is a TLAA, as defined in 10 CFR 54.3. Applicants must evaluate TLAAs in accordance with 10 CFR 54.21(c)(1). SER Section 4.4 documents the staff's review of the applicant's evaluation of this TLAA.

3.6.2.2.2 Degradation of Insulator Quality Due to Salt Deposits or Surface Contamination and Loss of Material Due to Mechanical Wear

The staff reviewed LRA Section 3.6.2.2.2 against the criteria in SRP-LR Section 3.6.2.2.2.

SRP-LR Section 3.6.2.2.2 states that degradation of insulator quality due to salt deposits or surface contamination may occur in high-voltage insulators. The GALL Report recommends further evaluation of plant-specific AMPs for plants located where there are potential salt deposits or surface contamination (e.g., in the vicinity of salt water bodies or industrial pollution). Loss of material due to mechanical wear caused by wind on transmission conductors may occur in high-voltage insulators. The GALL Report recommends further evaluation of a plant-specific AMP to ensure that these aging effects are adequately managed.

In LRA Section 3.6.2.2.2, the applicant stated that various airborne materials such as dust, salt, and industrial effluents can contaminate insulator surfaces. The buildup of surface contamination is gradual and in most areas washed away by rain. The glazed insulator surface aids this contamination removal. However, a large buildup of contamination enables the conductor voltage to track along the surface more easily and can lead to insulator flashover. Surface contamination can be a problem in areas where there are greater concentrations of airborne particles such as in the vicinity of facilities that discharge soot or near the sea coast where salt spray is prevalent. The applicant further stated that IP is not located near a sea coast where salt spray is prevalent, nor is IP located near a facility that discharges heavy pollutants. The applicant also stated that plant operating experience has not identified any issues associated with the buildup of surface contamination on the high-voltage insulators.

Since IP is not located near sources of industrial pollution or near the sea coast and the applicant's plant-specific operating experience has identified no issues associated with degradation of insulators, the staff finds that degradation of insulators due to salt deposit or surface contamination is not an applicable aging effect requiring management for high-voltage insulators at IP.

In the LRA, the applicant stated that mechanical wear is a potential aging effect for strain and suspension insulators subject to movement. Although this mechanism is possible, industry experience has shown that overhead transmission conductors do not normally swing. When subjected to a substantial wind, movement will subside after a short period. The applicant further stated that a review of IP operating experience determined that wear has not been apparent during routine inspection. Loss of material due to wear is not significant and will not cause a loss of intended function of the insulators.

The staff noted that although loss of material of insulators due to mechanical wear is possible, experience has shown that the transmission conductors do not normally swing significantly. When they do swing as the result of a substantial wind, they do not continue to swing for very long after the wind has subsided. Design and installation typically consider wind loading that can cause a transmission line and insulators to sway. The staff also noted that the applicant's routine inspections have not identified any loss of material of insulators due to mechanical wear. In addition, since the transmission conductors within the scope of license renewal at IP typically cover short spans, the surface areas exposed to wind loads are not significant. Therefore, the staff determines that the loss of material due to wear is not considered an aging effect that will cause a loss of intended function of the insulators at IP.

The staff finds that the applicant has addressed the potential degradation of insulator quality due to salt deposit or surface contamination and loss of materials due to mechanical wear. Based on the preceding technical justification, the staff concludes that the SRP-LR Section 3.6.2.2.2 criterion does not apply.

3.6.2.2.3 Loss of Material Due to Wind-Induced Abrasion and Fatigue, Loss of Conductor Strength Due to Corrosion, and Increased Resistance of Connection Due to Oxidation or Loss of Preload

The staff reviewed LRA Section 3.6.2.2.3 against the criteria in SRP-LR Section 3.6.2.2.3.

SRP-LR Section 3.6.2.2.3 states that loss of material due to wind-induced abrasion and fatigue, loss of conductor strength due to corrosion, and increased resistance of connection due to oxidation or loss of preload may occur in transmission conductors and connections and in switchyard bus and connections. The GALL Report recommends further evaluation of a plant-specific AMP to ensure that these aging effects are adequately managed.

SER Section 3.6.2.2.2 addresses the staff's review of loss of material due to wind-induced abrasion and fatigue for insulators.

The applicant stated in LRA Section 3.6.2.2.3 that the IP overhead transmission conductors subject to AMR are bounded by the Ontario Hydroelectric test population. The IP overhead transmission conductors have an ultimate strength margin greater than that of the Ontario Hydroelectric test cables after 80 years of service. The applicant also stated that the installation configuration at IP is representative of the tested samples, so the conclusions in the Ontario Hydro Study are valid for IP. However, the applicant did not provide information to substantiate the conclusion that the Ontario Hydroelectric Study is valid for IP. During the audit, the staff asked the applicant to explain in detail how the test conducted by Ontario Hydroelectric is valid for its plant (Audit Item 265). In a letter dated December 18, 2007, the applicant responded that corrosion in aluminum core steel-reinforced (ACSR) conductors is a very slow-acting mechanism and the corrosion rates depend on air quality, which includes suspended particles chemistry, sulfur dioxide (SO_2) concentration in air, precipitation, fog, chemistry, and meteorological conditions. Air quality in rural areas generally contains low concentrations of suspended particles and SO_2, which keeps the corrosion rate to a minimum. Although IP is located near urban areas, the applicant stated that there are no other industries in the immediate area. The applicant also stated that tests performed by Ontario Hydroelectric showed a 30 percent loss of an 80-year-old ACSR conductor due to corrosion. The IP transmission conductors for the 138-kV offsite power recovery are 1172-MCM aluminum conductor aluminum-reinforced (ACAR) 30/7 or 18/19 overhead transmission conductors. The Ontario Hydroelectric test did not include this specific conductor type, but these types are bounded because of the conductor size, configuration, and support strand material. The applicant further stated that the IP transmission cables have aluminum reinforcing strands, so the Ontario Hydroelectric ACSR transmission cables would bound the corrosion.

The staff reviewed the testing program performed by Ontario Hydroelectric to determine whether IP transmission conductors have adequate design margin. The study found that an 80-year-old ACSR conductor lost about 30 percent of conductor strength due to corrosion. A transmission conductor is replaced when it reaches a set percentage of composite conductor

strength. The National Electrical Safety Code (NESC) requires that tension on installed conductors be a maximum of 60 percent of the ultimate conductor strength. The NESC also sets the maximum tension that a conductor must be designed to withstand under heavy load requirements, which consider ice, wind, and temperature. The staff reviewed the requirements for the specific conductors included in the AMR at IP. The conductors with the smallest ultimate strength margin (4/0 ACSR) will be used to illustrate this strength margin. The ultimate strength and the NESC heavy load tension requirements of 4/0 (212 MCM) ACSR are 8350 pounds (lb) and 2761 lb, respectively. This heavy load tension is 33 percent of the ultimate strength (2761 lb/8350 lb), which is within the 60 percent requirement. The margin between the NESC heavy load and the ultimate strength is 5589 lb; this is 67 percent of the ultimate strength margin. The Ontario Hydroelectric Study showed that an 80-year-old conductor lost 30 percent of composite conductor strength due to corrosion. In the case of the 4/0 ACSR transmission conductors, a 30 percent loss of ultimate strength would mean that there would still be an ultimate strength margin of 37 percent between the NESC requirement and the actual conductor strength. The 4/0 ACSR conductors have the lowest initial design margin among the transmission conductors included in the NESC. The IP transmission conductors are ACAR, so the corrosion would be less than that found in the Ontario Hydroelectric ACSR transmission conductors. The transmission conductors at IP2 and IP3 are 1172-MCM ACAR, which are bigger than the 212-MCM conductors as illustrated. This shows that transmission conductors at IP will have ample strength through the period of extended operation.

In LRA Section 3.6.2.2.3, the applicant stated that the design of the transmission conductor bolted connections at IP precludes torque relaxation and corrosion, and the plant-specific operating experience has not identified any failures of switchyard connection due to aging. The type of bolting plate and the use of Belleville washers are the industry standard to preclude torque relaxation. IP design incorporates the use of Belleville washers on bolted electrical connections of dissimilar metals to compensate for temperature changes, maintain the proper torque, and prevent loosening. This method of assembly is consistent with the good bolting practices recommended by industry guidelines (EPRI TR-104213, "Bolted Joint Maintenance & Application Guide," issued December 1995). Before tightening of the connection, the bolted connections and washers are coated with an antioxidant compound (a grease-type sealant) to prevent the formation of oxides on the metal surface and to prevent moisture from entering the connection, thus reducing the chances of corrosion. The applicant stated that operating experience shows that this method of installation provides a corrosion-resistant, low-electrical-resistance connection. In addition, the applicant stated that the transmission connections are included in the infrared predictive maintenance of the 138-kV switchyard, which verifies the effectiveness of the connection design and installation practices. The infrared predictive maintenance is performed at least once every year. The applicant also stated that aluminum bus exposed to the service conditions of the switchyards does not experience any appreciable aging effects except minor oxidation, which does not impact the ability of the switchyard bus to perform its intended functions. In addition, the applicant stated that connection surface oxidation and loosening of bolted connections for aluminum switchyard bus are not applicable, since the switchyard bus connections are welded connections. However, the flexible conductors, which are welded to the switchyard bus, are bolted to the other switchyard components. The infrared predictive maintenance also includes these switchyard component connections.

The staff noted that connections to the switchyard bus are welded. However, the conductor connections are generally of the bolted category. Components in the switchyard are exposed to

precipitation. Connection materials exposed to the service conditions of the switchyard do not experience any appreciable aging effects except minor oxidation of the exterior surfaces, which does not impact the ability of the switchyard bus to perform its intended function. The staff also noted that preload of bolted switchyard bus connections is maintained by the appropriate design and the use of lock and Belleville washers that absorb vibration and prevent loss of preload. Using an antioxidant compound (a grease-type sealant) before tightening the connection prevents the formation of oxides on the metal surface and prevents moisture from entering the connection, thus reducing the chances of corrosion. Industry operating experience shows that this method of installation provides a corrosion-resistance connection of low electrical resistance. The applicant stated that the connections at the switchyard are periodically evaluated via thermography as part of preventive maintenance. The staff concludes that the applicant has adequately addressed the aging mechanism of increased resistance of connections due to oxidation or loss of preload because the method of assembly is in accordance with EPRI TR-104213 recommendations which is consistent with the GALL Report; conductor bolted connections are subject to periodic thermography; and no adverse operating experience conditions exist at IP.

For those items that apply to LRA Section 3.6.2.2.3, the staff determined that the applicant has addressed loss of material, loss of conductor strength, and increased resistance connections or loss of preload. The staff concludes that the applicant has met the criteria of SRP-LR Section 3.6.2.2.3

3.6.2.2.4 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 documents the staff's evaluation of the applicant's QA program.

3.6.2.3 AMR Results Not Consistent with or Not Addressed in the GALL Report

In LRA Table 3.6.2-1, the staff reviewed additional details of the AMR results for material, environment, AERM, and AMP combinations not consistent with or not addressed in the GALL Report.

In LRA Table 3.6.2-1, the applicant indicated via Notes F through J that the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report. The applicant provided further information about how it will manage the aging effects. Specifically, Note F indicates that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR line item component, material, and environment combination is not evaluated in the GALL Report. Note I indicates that the aging effect identified in the GALL Report for the line item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

For component type, material, and environment combinations not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation. The staff's evaluation is documented in the following sections.

3.6.2.3.1 Electrical and I&C Components—Summary of Aging Management Review—LRA Tables 3.6.1 and 3.6.2-1

The staff reviewed LRA Table 3.6.2-1, which summarizes the results of AMR evaluations for the electrical and I&C system component groups.

In LRA Table 3.6.1, under Item 3.6.1-10, "Metal enclosed bus—Enclosure assemblies," the applicant stated that an AMR is not required for enclosure elastomers because they are consumables. Consumables are considered short-lived or periodically replaced. However, the staff noted that the GALL Report, Volume 2, Item VI.A-12, identifies elastomers as a commodity type that requires an AMP. Therefore, by letter dated April 29, 2008, in RAI 3.6.2.3-1, the staff asked the applicant to confirm that for the in-scope metal-enclosed buses, there are no other elastomers or gaskets other than the access door gaskets. For access door elastomers, the staff requested that the applicant provide a technical justification of the exclusion of these components from an AMR. In a letter dated May 28, 2008, the applicant stated that based on site documents, the in-scope 6.9-kV and the 480-volt (V) metal-enclosed buses do not contain elastomers, except for the gaskets that provide a seal around the edge of the access covers. The applicant further stated that during the period of extended operation, the access cover gasket will be replaced periodically in conjunction with preventive maintenance inspections. Since the access cover is replaced based on a specified time period, it is not subject to an AMR per 10 CFR 54.21(a)(1)(ii). The staff finds the applicant's response acceptable because, based on site documents, the in-scope 6.9-kV and the 480-V metal-enclosed buses do not contain elastomers, except for the gaskets that provide a seal around the edge of the access covers. During the period of extended operation, the access cover gasket will be replaced periodically in conjunction with preventive maintenance inspections. Since the access cover gasket is replaced based on a specified time period, it is not subject to AMR per 10 CFR 54.21(a)(1)(ii).

<u>High-Voltage Power Cables</u>

In LRA Table 3.6.2-1, the applicant stated that IP2 138-kV direct burial insulated transmission cables (*passive electrical for station blackout recovery*) have no aging effects requiring management. The applicant indicated (by Note J) for material, environment, aging effect, and AMP that neither the component nor the material and environment combination is evaluated in the GALL Report for meeting the component's intended electrical function. The plant-specific Note 602 for this item in LRA Table 3.6.2-1 states that it is not subject to water treeing, since it is designed for continuously wet conditions. Industry and plant operating experience has not provided any information on failures of this type of cable. In addition, in its December 18, 2007, response to the NRC Audit Item 266 concerning the qualification of this cable for continuous submerged condition, the applicant stated that the aging effects caused by moisture and voltage stress are not applicable to this cable because the lead sheath prevents moisture intrusion.

Pursuant to 10 CFR 54.21(a)(3), the applicant must demonstrate that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation. Therefore, by letter dated May 28, 2008, in RAI 3.6.2.3-2, the staff requested that the applicant explain why an AMP is not required to manage the potential loss of dielectric strength leading to reduced insulation resistance and electrical failure due to aging mechanisms such as moisture and water intrusion, water treeing,

elevated operating temperature, voltage stress, and galvanic corrosion. The staff also asked the applicant to provide details of the purchase specification and testing requirements of cables and to explain how the aging effects are managed for pot assemblies (termination ends of the cables).

In its response, dated June 26, 2008, the applicant provided its technical justification of why an AMP is not required to manage the potential loss of dielectric strength leading to reduced insulation resistance and electrical failure of the cables and its termination ends (pot assemblies). The applicant provided the following technical basis to show that the cables and their terminations are not susceptible to the aging effects caused by moisture intrusion, water treeing, elevated operating temperature, voltage stress, and galvanic corrosion because of the design features of cables:

- The main components of the IP2 138-kV solid dielectric transmission cables are an extruded 0.125-inch polyethylene (PE) jacket, a 0.125-inch lead sheath, copper woven fabric expanding (swellable) tape, an extruded insulation shield, cross-linked polyethylene (XLPE) insulation, an extruded conductor shield, and a compacted 750-MCM copper conductor. Radial water sealing is achieved by the corrosion-resistant lead sheath, and longitudinal water sealing is achieved with a water swelling material under the lead sheath. The IP2 cables are installed in a duct bank within the Buchanan substation. These cables are not installed in a continuously wet condition, but it is assumed that the cables are exposed to significant moisture (they are wet for more than a few days). Since the lead sheath prevents moisture intrusion into the XLPE insulation of the cables, the insulation will not develop water trees. There are no aging effects due to aging mechanisms such as moisture and water intrusion or water treeing. Since there are no aging effects, an AMP is not required. In addition, the design of the circuit precludes voltage stress that is not associated with moisture intrusion.

- Based on the plant drawing, the construction of the IP2 138-kV solid dielectric transmission cables is the same as that of a submarine cable without the layer of armor wires and its associated anticorrosion barrier. Therefore, the IP2 138-kV solid dielectric transmission cable is comparable to a submarine cable for protecting the dielectric insulation from exposure to moisture.

- The cable is designed for direct burial but is installed in an underground duct bank. The purchase specification for the cable required that the cable and joint design be impervious to both water and hydrocarbon-based liquids, so that neither water nor hydrocarbon-based liquids will have any deleterious effect on any part of the cable or joints.

- The cable design accounts for voltage stress caused by switching transients. The maximum operational voltage is 145 kV, and the cable rating is 245 kV. The minimum impulse withstand voltage for this cable is 815 kV, and the basic impulse level (BIL) rating is 650 kV. Since the cable rating is higher than the operational voltage and the minimum impulse withstand voltage is higher than the BIL rating, voltage stress will not create aging effects requiring management.

- The purchase specification required the solid dielectric cable system to meet the Association of Edison Illuminating Companies (AEIC) Specification CS7, "Specification

for Crosslinked Polyethylene Insulated Shielded Power Cables Rated 69–138 kV." The cable purchase specification required that the cable be supplied with a moisture barrier, which was a metallic (lead) sheath, and longitudinal water sealing with a water swelling material under the lead sheath. AEIC CS7 required the items to pass an initial high-potential proof test. The cable was tested at the manufacturing plant using 60-hertz alternating current voltage. The shielded cables were required to meet the corona extinction level voltage. The shielded cables were to be free of partial discharge at voltages well above operating voltages. The specifications and installation procedures specified receipt inspection and post-installation testing. In addition to these factory tests, the plant modification process required a direct current high-potential test after installation. The cable passed the AEIC CS7-87 test specifications.

- The conductor and the insulation have an extruded shield. The lead sheath is not in direct contact with another conducting material. Therefore, the potential galvanic corrosion associated with a submarine cable between the extruded lead sheath and the copper armor wires is not applicable to the IP2 cable, since there is not a layer of armor wires. Therefore, galvanic corrosion of the cable will not create aging effects requiring management.

- The IP2 138-kV solid dielectric transmission cable rating based on temperature considerations and installation method (including conductor configuration) is 575 amps continuous. The worst-case continuous load is about 330 amps. The worst-case continuous load is less than 60 percent of the rating of the cable, so ample design margin exists. Based on the available design margin, elevated operating temperature will not result in aging effects requiring management.

- The current maintenance program for the IP2 138-kV solid dielectric transmission cable performed by IP2 includes a walkdown of the IP2 138-kV offsite power feeder from the IP2 station auxiliary transformer to the Buchanan substation breakers. This walkdown includes inspection of the accessible portions of the 138-kV solid dielectric underground transmission cable. No periodic tests are performed under the IP2 maintenance program; however, IP2 continuously monitors these cables for voltage and load.

- Manufacturing defects or damage caused by shipping and installation are possible mechanisms contributing to water treeing and insulation breakdown; however, these are event-driven mechanisms not related to aging. Receipt inspections and post-installation testing minimize these conditions. These events result in premature failures, but the IP2 138-kV solid dielectric transmission cable, which was installed in late 1994, has experienced no such failures.

- The EPRI electrical handbook and Section XI.E3 of the GALL Report state that continuous wetting and continuous energization are not significant concerns for submarine cables, and the IP2 138-kV solid dielectric transmission cable has the same features as a submarine cable for preventing moisture intrusion. Therefore, no aging effects associated with moisture and voltage stress require management during the period of extended operation.

- The IP2 138-kV solid dielectric transmission cable has oil-filled pothead connections on each end. The potheads are sealed and filled with oil pressurized with a local nitrogen

tank. A pressure switch that alarms in the Buchanan substation control room continuously monitors the pressure of the oil. The Buchanan substation control room alarm re-flashes in the IP2 control room. The oil in the pothead prevents moisture and oxygen intrusion into the connection but does not contribute to the BIL rating for the pothead, nor does the oil provide insulation for the connection. Therefore, the oil does not require a specific dielectric strength to support the connection's intended function. Because the oil prevents moisture and oxygen intrusion, corrosion of this connection is not an applicable aging mechanism. Furthermore, the applicant performs routine maintenance which entails periodic visual inspections of the potheads including the seals between the pothead and the 138-kV solid dielectric cables and between the pothead and the nitrogen connections. The applicant performs visual inspections of the potheads at least once per year. This visual inspection, combined with continuous monitoring, ensures the maintenance of an environment that precludes aging due to moisture and oxygen.

Based on review of the above information, the staff agrees that the IP2 138-kV XLPE cables have design features to prevent the potential loss of dielectric strength leading to reduced insulation resistance and electrical failure. However, the staff does not agree with the applicant's assessment that the IP2 cables do not require an AMP to manage the potential aging mechanism as discussed above during the period of extended operation. The staff notes that, as specified in GALL AMP XI.E3, Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program, operating experience has shown that XLPE or high-molecular-weight polyethylene insulation materials are most susceptible to water tree formation. The formation and growth of water trees vary directly with operating voltage. These cables are installed in an environment where the cables could be submerged and/or in wet conditions.

The staff noted that IP2 neither has an existing program to inspect and remove water from the duct bank nor has proposed any such program for the period of extended operation. The applicant's response to Generic Letter 2007-01, "Inaccessible or Underground Power Cable Failures that Disable Accident Mitigation Systems or Cause Plant Transients," dated May 7, 2007 (ADAMS Accession number ML071350410), indicates that there were two 600-V cable failures that had lead jackets which were installed in a wet environment. For one of the table entries, the applicant lists the contributing cause to the degradation of the cable as submergence of cable for an extended period of time. In addition, the staff noted that licensees have reported several XLPE cable failures (shielded and non-shielded) in 5-kV, 8-kV, 15-kV, and 35-kV applications. Cable failures have a variety of causes, including exposure to electrical transients or aging effects caused by moisture intrusion and water treeing due to adverse abnormal environmental conditions during operation. Contributing causes, such as manufacturing defects or damage caused by shipping and installation, could initiate the aging effects. The likelihood of failure from any of these causes increases over time as the cable insulation degrades.

The staff determined that IP2 cable life depends on the dielectric properties and that the applicant needs to address how it plans to monitor the degradation and manage the aging effects during the period of extended operation. In addition, neither the vendor nor the applicant has established any qualified life for these cables.

To address the staff's concern, the applicant stated that it would revise its aging management evaluations in an amendment to the LRA. In a letter dated August 14, 2008, the applicant amended the LRA to state that LRA Sections A.2.1.28 and B.1.29 were modified to add the 138-kV underground transmission cable, which is part of the Unit 2 offsite power path, to the Periodic Surveillance and Preventive Maintenance Program. The routine maintenance will include vendor-recommended testing and inspections as stated in the amended text for LRA Sections A.2.2.28 and B.1.29. SER Section 3.0.3.3.7 documents the staff's evaluation of the applicant's *Periodic Surveillance and Preventive Maintenance Program.*

The staff's concerns identified in RAI 3.6.2.3-2 are resolved because the applicant has established an AMP to manage the potential loss of dielectric strength leading to reduced insulation resistance and electrical failure of the cables and its termination ends.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the electrical and I&C system components within the scope of license renewal and subject to an AMR will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.7 Conclusion for Aging Management Review Results

The staff reviewed the information in LRA Section 3, "Aging Management Review Results," and LRA Appendix B, "Aging Management Programs and Activities." On the basis of its review of the AMR results and AMPs, the staff concludes that the applicant has demonstrated that the aging effects will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the applicable UFSAR supplement program summaries and concludes that the supplement adequately describes the AMPs credited for managing aging, as required by 10 CFR 54.21(d).

With regard to these matters, the staff concludes that there is reasonable assurance that the applicant will continue to conduct the activities authorized by the renewed licenses will continue to be conducted in accordance with the CLB, and any changes made to the CLB, in order to comply with 10 CFR 54.21(a)(3), are in accordance with the Atomic Energy Act of 1954, as amended, and NRC regulations.

SECTION 4

TIME-LIMITED AGING ANALYSES

4.1 Identification of Time-Limited Aging Analyses

This section of the safety evaluation report (SER) addresses the identification of time-limited aging analyses (TLAAs). In Sections 4.2 through 4.7 of the license renewal application (LRA), Entergy Nuclear Operations, Inc. (Entergy or the applicant) addressed the TLAAs for Indian Point Nuclear Generating Unit Nos. 2 and 3 (IP2 and IP3). SER Sections 4.2 through 4.8 document the review of the TLAAs conducted by the staff of the U.S. Nuclear Regulatory Commission (NRC or the staff).

TLAAs are certain plant-specific safety analyses that involve time-limited assumptions defined by the current operating term. Pursuant to Title 10, Section 54.21(c)(1), of the *Code of Federal Regulations* (10 CFR 54.21(c)(1)), applicants must list TLAAs as defined in 10 CFR 54.3, "Definitions."

In addition, pursuant to 10 CFR 54.21(c)(2), applicants must list plant-specific exemptions granted under 10 CFR 50.12, "Specific Exemptions," based on TLAAs. For any such exemptions, the applicant must evaluate and justify the continuation of the exemptions for the period of extended operation.

4.1.1 Summary of Technical Information in the Application

To identify the TLAAs, the applicant evaluated calculations for IP2 and IP3 against the six criteria specified in 10 CFR 54.3. The applicant indicated that it has identified the calculations that met the six criteria by searching the current licensing basis (CLB). The CLB includes the updated final safety analysis report (UFSAR), technical specifications, the technical requirements manual, fire protection program documents, NRC safety evaluation reports, licensing correspondence, and applicable vendor reports. In LRA Table 4.1-1, "List of IP2 TLAA and Resolution," and LRA Table 4.1-2, "List of IP3 TLAA and Resolution," the applicant listed the following applicable TLAAs:

- reactor vessel (RV) neutron embrittlement analyses
- metal fatigue analyses
- environmental qualification (EQ) analyses of electrical equipment
- concrete containment tendon prestress analyses
- containment liner plate and penetrations fatigue analyses
- leak before break (LBB)
- steam generator flow-induced vibration

Pursuant to 10 CFR 54.21(c)(2), the applicant stated that it did not identify exemptions granted under 10 CFR 50.12 based on a TLAA, in accordance with 10 CFR 54.3.

4.1.2 Staff Evaluation

LRA Section 4.1 lists the IP2 and IP3 TLAAs. The staff reviewed the information to determine whether the applicant had provided sufficient information pursuant to 10 CFR 54.21(c)(1) and 10 CFR 54.21(c)(2).

As defined in 10 CFR 54.3, TLAAs meet the following six criteria:

(1) involve systems, structures, and components within the scope of license renewal, pursuant to 10 CFR 54.4(a)

(2) consider the effects of aging

(3) involve time-limited assumptions defined by the current operating term (40 years)

(4) are determined to be relevant by the applicant in making a safety determination

(5) involve conclusions, or provide the basis for conclusions, related to the capability of the system, structure, and component to perform its intended functions, pursuant to 10 CFR 54.4(b)

(6) are contained or incorporated by reference in the CLB

The applicant reviewed the list of common TLAAs in "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" (SRP-LR), issued September 2005. The applicant listed TLAAs applicable to IP2 and IP3 in LRA Tables 4.1-1 and 4.1-2.

As required by 10 CFR 54.21(c)(2), the applicant must list all exemptions granted in accordance with 10 CFR 50.12, based on TLAAs, and evaluated and justified for continuation through the period of extended operation. The LRA states that each active exemption was reviewed to determine whether it was based on a TLAA. The applicant did not identify any TLAA-based exemptions. Based on the information provided by the applicant regarding the results of the applicant's search of the CLB to identify these exemptions, the staff has determined, in accordance with 10 CFR 54.21(c)(2), that there are no TLAA-based exemptions which have been justified for continuation through the period of extended operation.

4.1.3 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable list of TLAAs, as required by 10 CFR 54.21(c)(1), and that no exemptions have been granted on the basis of a TLAA for which continuation has been justified during the period of extended operation as specified in 10 CFR 54.21(c)(2).

4.2 Reactor Vessel Neutron Embrittlement

The regulations governing RV integrity are in 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities." As required by 10 CFR 50.60, "Acceptance Criteria for Fracture Prevention Measures for Lightwater Nuclear Power Reactors for Normal Operation," all light-water reactors meet the fracture toughness, pressure-temperature (P-T) limits, and material surveillance program requirements for the reactor coolant pressure boundary pursuant to Appendices G, "Fracture Toughness Requirements," and H, "Reactor Vessel Material

Surveillance Program Requirements," to 10 CFR Part 50. In addition, 10 CFR 50.61, "Fracture Toughness Requirements for Protection against Pressurized Thermal Shock Events," requires that all pressurized-water nuclear power reactors meet specific screening criteria for protection against RV failure from pressurized thermal shock (PTS) events. The applicant's CLB analyses of RV fracture toughness reduction for 40 years are TLAAs.

A summary of the RV neutron embrittlement TLAA for each unit follows. Forty-eight effective full-power years (EFPY) are projected for the end of the period of extended operation (60 years) based on actual capacity factors from the start of commercial operation until 2005 and on a projected average capacity factor of 95 percent from 2005 until the end of the period of extended operation.

4.2.1 Reactor Vessel Fluence

4.2.1.1 Summary of Technical Information in the Application

LRA Section 4.2.1 summarizes the evaluation of RV neutron fluence for the period of extended operation, projecting neutron exposure levels for the RVs for an operating period extending to 48 EFPYs. These calculations utilized discrete ordinates (S_n) transport analysis to determine the neutron radiation environment within the RV and the surveillance capsules.

The IP2 evaluation calculated plant- and fuel-cycle-specific exposure parameters of fast neutron fluence (E > 1.0 million electron volts (MeV)) and iron atom displacements for the first 16 reactor operating cycles (1973–2004). The fuel cycle designs analyzed in these calculations have been implemented. The calculations also included analyses for three other cycle designs created as part of the 2003 stretch power uprate study; therefore, the 48-EFPY projections included the effects of stretch power uprate. The projected 48-EFPY peak beltline neutron fluence level of 1.906×10^{19} neutrons per square centimeter (n/cm^2)(at the 45-degree azimuth position) is for all beltline materials except axial welds, which are located at 0-, 15-, and 30-degree azimuth positions. The maximum projected 48-EFPY peak fluence level for the beltline axial welds is 1.295×10^{19} n/cm^2 at the 30-degree azimuth position. The one-fourth of the way through the vessel wall (¼T) neutron fluence level was determined by applying Equation (3) of Regulatory Guide (RG) 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials," issued May 1988, to an RV thickness of 8.625 inches, yielding a neutron fluence of 7.72×10^{18} n/cm^2 for beltline axial welds and 1.136×10^{19} n/cm^2 for all other beltline materials.

The IP3 evaluation calculated plant- and fuel-cycle-specific exposure parameters of fast neutron fluence (E > 1.0 MeV) and iron atom displacements for the first 13 reactor operating cycles (1976–2005). The fuel cycle designs analyzed in these calculations have been implemented. The calculations also included analyses for three other cycle designs created as parts of the 2003 stretch power uprate study; therefore, the 48-EFPY projections include the effects of the stretch power uprate. The projected 48-EFPY peak beltline neutron fluence level of 1.560×10^{19} n/cm^2 (at the 45-degree azimuth position) is for all beltline materials including axial welds. The ¼T neutron fluence level was determined by applying RG 1.99, Revision 2, Equation (3) to an RV thickness of 8.625 inches, yielding a neutron fluence of 9.298×10^{18} n/cm^2.

4.2.1.2 Staff Evaluation

Neutron Fluence for RV Surveillance Capsules. The staff reviewed the applicant's evaluations of the RV surveillance capsules for the materials in the RV of IP2 as described in the following reports:

- Westinghouse Commercial Atomic Power (WCAP)-15629, Revision 1, "Indian Point Unit 2 Heatup and Cooldown Curves for Normal Operation and PTLR Support Documentation"
- WCAP-16251, "Analysis of Capsule X from Entergy's Indian Point Unit 3 Reactor Vessel Radiation Surveillance Program"
- WCAP-15805, "Analysis of Capsule X from the Carolina Power and Light Company H.B. Robinson Unit 2 Reactor Vessel Radiation Surveillance Program"

WCAP-15629, Revision 1, is contained in a January 11, 2002, letter from Entergy. WCAP-16251 is contained in a July 29, 2004, letter from Entergy. WCAP-15805 is contained in an April 25, 2002, letter from Carolina Power and Light Company. WCAP-16251, Section 6; WCAP-15805, Section 6; and WCAP-15629, Revision 1, Appendix B, describe the methodology used for determining the neutron fluence for the surveillance capsules. The staff finds that the methodology documented in WCAP-16251, Section 6; WCAP-15805, Section 6; and WCAP-15629, Revision 1, Appendix B, is acceptable because (1) it has been extensively benchmarked as described in WCAP-15557, "Qualification of Westinghouse Pressure Vessel Neutron Fluence Evaluation Methodology"; (2) it adheres to the guidance in RG 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," issued March 2001; and (3) it uses plant-specific dosimetry results to provide additional plant-specific validation of the generic benchmarking in WCAP-15557.

The staff reviewed the applicant's evaluations of the RV surveillance capsules for the materials in the RV of IP3 as described in report WCAP-16251. The staff finds the methodology in WCAP-16251 acceptable as discussed above.

Neutron Fluence for Reactor Vessel. In LRA Section 4.2.1, the applicant provided its peak beltline fluence level for 48 EFPY for IP2 and IP3. Since the Charpy upper-shelf energy (USE) and pressurized thermal shock (PTS) analyses utilize the neutron fluence at 48 EFPY to represent the neutron fluence for the reactor vessels at the end of the period of extended operation, the staff requested additional information regarding (a) what capacity factors and neutron flux were assumed for each unit from the last refueling outage to the end of the period of extended operation to result in 48 EFPY at the end of the period of extended operation, and why these capacity factors and neutron flux values are applicable for determining the neutron fluence for the reactor vessels at the end of the period of extended operation; and (b) how future capacity factors, neutron flux and neutron fluence values will be monitored to ensure 48 EFPY values bound the actual conditions of the reactor vessels at the end of the period of extended operation. In its November 28, 2007 response to the request for additional information (RAI) 4.2.1-1, the applicant described the impact of plant operation on the RV neutron fluence and the method of monitoring the EFPY and neutron fluence. The applicant stated the following:

> Neutron flux corresponding to the licensed reactor power rating was assumed from the end of the last refueling outage through the end of the period of extended operation. A two-year cycle (730 days), includes a 25-day refueling outage (705 operating days). IP2 would have to operate at a capacity factor of 0.99 during the periods between refueling outages to attain 48 EFPY at the end of the period of extended operation (September 13, 2033).
>
> IP3 would have to operate at a capacity factor of greater than 1.0 during the periods between refueling outages to attain 48 EFPY at the end of the period of extended operation (December 15, 2035).
>
> Future neutron fluence values will be monitored to ensure 48 EFPY values bound the actual conditions of the reactor vessels in the same way current neutron fluence is monitored to ensure P-T curves remain valid. Plant service lifetime in EFPY is routinely reviewed by engineering and licensing personnel. Additionally, accumulated reactor vessel fluence is checked on a cyclic basis as part of the core reload change package. Because of shutdowns for refueling, plant operation cannot exceed 48 EFPY. If rated power level is increased at a future date, the associated engineering evaluations will ensure the resulting increase in flux is properly accounted for in determining the neutron fluence for the reactor vessels at the end of the period of extended operation.

During a telephone call with the applicant on December 3, 2007, the staff explained that in RAI 4.2.1-1 regarding neutron fluence and flux, the staff was asking for specific fluence and flux values and the source of those calculated values and requested that this information be provided. In addition, the NRC staff requested that Entergy provide confirmation that the referenced source of the surveillance data satisfies the guidance Regulatory Guide 1.190, and that the surveillance data have been used in the PTS and Charpy USE analyses.

By letter dated January 17, 2008, the applicant supplemented its response to RAI 4.2.1-1, and identified the neutron fluxes assumed for all future operating cycles. However, the January 17, 2008 response did not identify the methodology for determining the neutron fluxes for the RV in IP2. In a subsequent telephone conference call held on May 7, 2008, the applicant indicated that it utilized the neutron fluence calculation methodology documented in WCAP-16157-P, "Indian Point Nuclear Generating Unit No. 2 Stretch Power Uprate NSSS and BOP Licensing Report," issued January 2004. This report references WCAP-15629, Revision 1. Since the methodology for calculating neutron fluence in WCAP-15629, Revision 1, is acceptable for the reasons specified earlier in this section, the neutron fluence calculated by the applicant for the IP2 RV is acceptable. Similarly, since the applicant calculated the neutron fluxes for the RV in IP3 using the methodology documented in WCAP-16251, Section 6, the staff finds the fluence calculations acceptable.

The capacity factor is the ratio of the number of full-power days of operation to the number of calendar days per fuel cycle. A 2-year cycle with 705 days of full-power operation and 25 days of refueling would result in a capacity factor of 0.97. Using the neutron flux reported by the applicant, the staff confirmed that the applicant would have to exceed a capacity factor of 0.99 during future cycles to reach the neutron fluences that are reported for the RVs in IP2 and IP3 in LRA Tables 4.2-1 through 4.2-6. LRA Tables 4.2-1 and 4.2-2 provide the neutron fluences for

the RV materials for the Charpy upper-shelf energy (USE) evaluations for IP2 and IP3, respectively. LRA Tables 4.2-3 and 4.2-4 provide the neutron fluence for the PTS evaluations for IP2 and IP3, respectively. LRA Tables 4.2-5 and 4.2-6 provide the neutron fluence for adjusted reference temperature for IP2 and IP3, respectively. Since normal plant operation would only result in a capacity factor of 0.97 and the applicant monitors the EFPY and neutron fluence, the staff finds that the neutron fluences documented in LRA Tables 4.2-1 through 4.2-6 are acceptable for evaluating the impact of neutron radiation on RV integrity.

The staff requested that the applicant evaluate the effect of neutron fluence at the end of the period of extended operation on the IP2 and IP3 nozzle shell courses. In a letter dated September 24, 2008, the applicant determined the impact of neutron fluence on the plates, welds, and nozzle forgings in the IP2 and IP3 nozzle shell courses. The neutron fluence for the IP3 shell course was projected using the results of the IP2 analysis. The results of the IP2 analysis are applicable to IP3 since the IP2 and IP3 vessel geometries are the same, and the applicant uses similar fuel loading patterns. The outlet and inlet nozzle-to-shell welds were determined to have neutron fluences of less than $1x10^{17}$ n/cm^2 (E > 1.0 MeV) at the end of the period of extended operation. Since RG 1.99, Revision 2 indicated that neutron fluence values of less than $1x10^{17}$ n/cm^2 (E > 1.0 MeV) do not result in significant radiation embrittlement, licensees do not need to evaluate the impact of radiation embrittlement on components whose neutron fluence is less than $1x10^{17}$ n/cm^2 (E > 1.0 MeV). In its letter dated September 24, 2008, the applicant indicated that the nozzle shell plates, nozzle shell longitudinal welds, and the nozzle-to-intermediate shell circumferential weld in the IP2 and IP3 vessels would have neutron fluence values greater than $1x10^{17}$ n/cm^2 (E > 1.0 MeV) at the end of the period of extended operation. Therefore, the applicant included these components in its Charpy USE and PTS evaluations. The staff's evaluation of the applicant's Charpy USE evaluation of these components and of the PTS evaluation is documented in SER Sections 4.2.2.2 and 4.2.5.2, respectively.

In its September 24, 2008 letter, the applicant committed to update the neutron fluence calculations should there be changes in the fuel loadings that do not support the assumed similarities for the projection of the vessel fluences for future cycle loadings through the end of the period of extended operation (Commitment 38). This is acceptable.

4.2.1.3 UFSAR Supplement

The applicant provided an UFSAR supplement summary description of its TLAA evaluation of RV neutron fluence in LRA Sections A.2.2.1 and A.3.2.1, as amended by letter dated June 11, 2008, and A.2.2.1.1 and A.3.2.1.1. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address RV neutron fluence is adequate.

4.2.1.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for reactor vessel neutron fluence, the analyses have been projected to the end of the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.2.2 Charpy Upper-Shelf Energy

4.2.2.1 Summary of Technical Information in the Application

LRA Section 4.2.2 summarizes the evaluation of Charpy USE for the period of extended operation. Appendix G to 10 CFR Part 50 requires the applicant to ensure that the reactor coolant pressure boundary pressure-retaining components made of ferritic materials meet American Society of Mechanical Engineers (ASME) Code fracture toughness requirements, as supplemented, during system hydrostatic tests and any condition of normal operation, including anticipated operational occurrences. For RV beltline materials, reference temperature nil ductility (RT_{NDT}) and Charpy USE values must account for the effects of neutron radiation, determined by consideration of the neutron fluence at the deepest point on the crack front of the flaw assumed in the analysis. RV beltline materials must maintain Charpy USE values of no less than 50 foot-pounds (ft-lb) throughout the life of the vessel. RG 1.99, Revision 2, provides two methods (positions) for determining Charpy USE. Position 1 applies to material with no surveillance data available. Position 2 applies to material with surveillance data. Position 1 determines the percent drop in Charpy USE for a stated copper content and neutron fluence by reference to RG 1.99, Revision 2, Figure 2, in accordance with RG 1.99, Revision 2, Section 1.2. This percentage drop is then applied to the initial Charpy USE value to obtain the adjusted Charpy USE value. Position 2 determines the percent drop in Charpy USE by plotting the available data on Figure 2 and fitting the data with a line parallel to the predetermined lines bounding all the plotted points in accordance with Section 2.2 of RG 1.99, Revision 2.

For IP2, the applicant stated that the Charpy USE values were based on the maximum projected 48-EFPY beltline fluence. The beltline region chemistry and surveillance data, including the unirradiated Charpy USE values, were from the second Reactor Vessel Integrity Database (RVID2) and clarified in WCAP-15629, Revision 1. The projected 48-EFPY peak beltline neutron fluence level at the clad-base metal interface of 1.906×10^{19} n/cm^2 was applied to all beltline materials except the RV axial welds, where the expected peak fluence was 1.295×10^{19} n/cm^2. LRA Table 4.2-1 shows the resulting projected 48-EFPY Charpy USE drop and resulting ¼T Charpy USE. One intermediate shell plate (B2002-3) and one lower shell plate (B2003-1) have projected USE values that fall below 50 ft-lb during the period of extended operation. All remaining plate and weld beltline materials exceed 50 ft-lb at 48 EFPY. Section IV.A.1 of Appendix G to 10 CFR Part 50, requires licensees to take action when the 50 ft-lb end-of-life (EOL) USE criterion cannot be met. The lowest projected IP2 beltline plate material USE value through the period of extended operation was 47.4 ft-lb for intermediate shell plate B2002-3. An equivalent margins analysis, described in WCAP-13587, Revision 1, "Reactor Vessel Upper-Shelf Energy Bounding Evaluation for Westinghouse Pressurized Water Reactors," demonstrated that the minimum acceptable USE value for RV plate material in 4-loop plants like IP2 is 43 ft-lb. In the WCAP-13587, Revision 1, safety assessment, the staff concluded that the report demonstrated margins of safety equivalent to those of the ASME Code for beltline plate and forging materials. The IP2 USE values were acceptable because the projected 47.4 ft-lb lowest USE level for the IP2 beltline plate material through the period of extended operation for intermediate shell plate B2002-3 was above the 43 ft-lb minimum acceptable USE value for 4-loop plants as demonstrated in WCAP-13587, Revision 1. Furthermore, these values were consistent with SRP-LR, Section 4.2.2.1.1.2, and the H.B. Robinson, Unit 2, SER, as documented in NUREG-1785, "Safety Evaluation Report

Related to the License Renewal of H.B. Robinson Steam Electric Plant, Unit 2," issued March 2004.

For IP3, the applicant stated that the USE values were based on the maximum projected 48 EFPY beltline fluence and the beltline region chemistry and surveillance data, including the unirradiated percent drop in Charpy USE information summarized in the RVID2 database, with the projected 48-EFPY peak beltline fluence level of 1.560×10^{19} n/cm^2 at the clad-base metal interface conservatively applied to all beltline materials. The applicant's calculation of the 48 EFPY, ¼T neutron fluence level of 9.298×10^{18} n/cm^2 was in accordance with RG 1.99, Equation (3), based on a vessel thickness of 8.625 inches. LRA Table 4.2-2 displays the resulting projected 48-EFPY Charpy USE drop and resulting ¼T Charpy USE values. All plate and weld beltline materials exceed 50 ft-lb at 48 EFPYs and an equivalent margins analysis is not required.

The applicant stated that the TLAAs for USE are projected through the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

4.2.2.2 Staff Evaluation

The staff reviewed LRA Section 4.2.2 to verify that, pursuant to 10 CFR 54.21(c)(1)(ii), the analyses have been projected to the end of the period of extended operation.

Charpy Upper-Shelf Energy Evaluation. LRA Table 4.2-3 indicates that the ΔRT_{NDT} value caused by irradiation for the intermediate shell axial welds and the lower shell axial welds in IP2 were determined using surveillance data reported in WCAP-15629, Revision 1, "Indian Point Unit 2 Heatup and Cooldown Limit Curves for Normal Operation and PTLR Support Documentation." By letter dated October 29, 2007, the staff asked the applicant to provide neutron fluence values derived using a methodology that satisfies the guidance in RG 1.190, and to provide the surveillance data analysis required by 10 CFR 50.61(c)(2)(i).

By letter dated November 28, 2007, the applicant responded to the staff's RAI and stated that the fluences shown are based on the data taken before the RG 1.190 guidance was available. Therefore, Westinghouse used the information at hand and added a 15 percent penalty for a conservative margin. Revised fluences consistent with the guidance of RG 1.190 have been calculated by Westinghouse. In a telephone conference call with the applicant on December 4, 2007, the staff asked that Entergy provide confirmation that the referenced source of the surveillance data satisfies Regulatory Guide 1.190, and that the surveillance data have been used in the Pressurized Thermal Shock and Charpy Upper-Shelf Energy analyses.

By letter dated January 17, 2008, the applicant provided updated surveillance data for IP2 intermediate shell plates B2002-1, B2002-2, and B2002-3. WCAP-15629, Revision 1, Table C-1, reports the updated surveillance data. As a result of these data, the applicant revised the Charpy USE value for the limiting material, plate B2002-3 (LRA Table 4.2-1 in the January 17, 2008, letter), to 48.3 ft-lb at the end of the period of extended operation. The Charpy USE was projected using the methodology in RG 1.99, Revision 2, Section 2.2. To maximize the accuracy of the projection, the applicant used a spreadsheet and the equations for the RG 1.99, Revision 2, curves (available in NUREG/CR-5799, "Review of Reactor Pressure Vessel Evaluation Report for Yankee Rowe Nuclear Power Station [YAEC No. 1735],"

issued March 1992) to determine the percent drop in Charpy USE. The other beltline plates, B2003-1 and B2003-2, do not have surveillance data and have projected Charpy USE using the methodology in RG 1.99, Revision 2, Section 1.2.

The January 17, 2008, letter also provided an updated analysis for the Charpy USE for the intermediate shell axial welds and lower shell axial welds in IP2 at the end of the period of extended operation. Using the methodology in RG 1.99, Revision 2, Section 2.2, the applicant projected that these welds will have a Charpy USE value of 60.8 ft-lb at the end of the period of extended operation. Combustion Engineering fabricated these welds using Linde 1092 flux and heat number W5214 weld wire. The IP2, IP3, and H.B. Robinson RVs all contain this weld material in their surveillance capsules. WCAP-15629, Revision 1, Table C-1, documents the IP2 Charpy USE surveillance data. WCAP-16251-NP, Table 5-10, documents the IP3 Charpy USE surveillance data. WCAP-15805, Table 5-10, documents the H.B. Robinson Charpy USE surveillance data. The staff confirmed that the Charpy USE values reported in the applicant's January 17, 2008, letter for all beltline plates and welds in the IP2 RV were calculated in accordance with RG 1.99, Revision 2.

In its January 17, 2008, response to RAI 4.2.2-1, the applicant provided updated surveillance data and analysis for IP3 intermediate shell plate B2803-3. WCAP-16251-NP, Table 5-10, documents the updated surveillance. Using the methodology documented in RG 1.99, Revision 2, Section 2.2, the revised Charpy USE value for plate B2803-3 is 49.8 ft-lb at the end of the period of extended operation. Since plate B2803-3 is projected to be below 50 ft-lb, an equivalent margins analysis is required to demonstrate that it will provide margins of safety against fracture equivalent to those required by ASME Code, Section XI, Appendix G. The other beltline plates and welds do not have surveillance data and have Charpy USE values greater than 50 ft-lb at the end of the period of extended operation. Since there are no surveillance data for these plates and welds, the Charpy USE is projected using the methodology in RG 1.99, Revision 2, Section 1.2. The staff confirmed that the Charpy USE values reported in the applicant's January 17, 2008, letter for all IP3 RV beltline plates and welds were calculated in accordance with RG 1.99, Revision 2.

In a letter dated September 24, 2008, the applicant stated that the Charpy USE values for the nozzle shell plates, nozzle-to-shell longitudinal welds, and the nozzle-to-intermediate shell circumferential weld in the IP2 and IP3 vessels would be greater than 50 ft-lb at the end of the period of extended operation. These values were determined using the methodology documented in RG 1.99, Revision 2. Since the Charpy USE values are greater than 50 ft-lb, an equivalent margins analysis is not required and these components meet the requirements of Section IV.A.1.a of Appendix G to 10 CFR Part 50 for Charpy USE.

Equivalent Margins Analyses. Section IV.A.1.a of Appendix G to 10 CFR Part 50 requires that RV beltline materials have Charpy USE values in the transverse direction for base metal and along the weld for weld metal of no less than 50 ft-lb throughout the life of the RV, unless it is demonstrated in a manner approved by the Director, Office of Nuclear Reactor Regulation, that lower values of Charpy USE will provide margins of safety against fracture equivalent to those required by ASME Code, Section XI, Appendix G. In its January 17, 2008 letter, the applicant indicated that the analysis performed in WCAP-13587, Revision 1, demonstrated that the minimum acceptable Charpy USE value for RV plate material in 4-loop plants such as IP2 and IP3 is 43 ft-lb. The applicant asserted that IP2 and IP3 RVs were acceptable because the lowest Charpy USE values at the end of the period of extended operation in these RVs

(48.3 ft-lb for IP2 and 49.8 ft-lb for IP3) are greater than the 43 ft-lb minimum acceptable Charpy USE for 4-loop plants determined in WCAP-13587, Revision 1.

The applicant submitted WCAP-13587, Revision 1, for staff review and approval to demonstrate through fracture mechanics analyses that margins of safety against fracture exist that are equivalent to those required by ASME Code, Section XI, Appendix G, for beltline materials having Charpy USE values below the 50 ft-lb screening limit as required by 10 CFR Part 50, Appendix G, Section IV.A.1.a. The analysis in WCAP-13587, Revision 1, establishes a minimum acceptable Charpy USE value of 43 ft-lb for RVs in 4-loop Westinghouse designed plants. The staff reviewed WCAP-13587, Revision 1, in a safety assessment included in a letter dated April 21, 1994, to W.H. Rasin of the Nuclear Management and Resources Council. The staff concluded that the methodology employed in the report was consistent with the guidelines in ASME Code Case N-512, "Assessment of Reactor Vessels with Low Upper-Shelf Charpy Impact Energy Levels," and draft RG, DG-1023, "Evaluation of Reactor Pressure Vessels with Charpy Upper-Shelf Energy Less than 50 Ft-Lb," issued September 1993, and that the report demonstrates the margins of safety equivalent to those of the ASME Code. ASME Code Case N-512 provides criteria for demonstrating that RVs with Charpy USE values of less than 50 ft-lb have margins of safety against fracture equivalent to those required by ASME Code, Section XI, Appendix G. ASME Code Case N-512 requires that flaws be postulated in the RV at locations of predicted low Charpy USE and that the applied J-integral ($J_{applied}$) for these flaws be calculated and compared with the J-integral ($J_{material}$) fracture resistance of the material. The applicant calculated $J_{applied}$ for generic ASME Code Service Loading A, B, C, and D conditions and generic RV shell geometry. The $J_{material}$ was calculated using J-R data for the RV materials.

The staff's safety assessment for WCAP-13587, Revision 1 indicated that licensees must confirm that the bounding plate used in the report has a lower J-R curve than any beltline material in their RV. This safety assessment indicated that the J-R curve data proposed in WCAP-13587, Revision 1, for A533 Grade B plate and A302 Grade B modified (with nickel added) base materials were acceptable.

To demonstrate that the analyses in WCAP-13587, Revision 1, were applicable to IP2 and IP3, the staff, in RAI 4.2.2-2 dated October 29, 2007, requested that the applicant compare (1) the plate materials in the IP2 and IP3 RVs to the plate materials evaluated in WCAP-13587, Revision 1, (2) the RV shell geometry (wall thickness and inner radius) of the IP2 and IP3 RVs to the geometry used in the Westinghouse 4-loop analysis in WCAP-13587, Revision 1, and (3) the ASME Code Service Loading A, B, C, and D conditions for IP2 and IP3 to the ASME Code Service Loading A, B, C, and D conditions evaluated in WCAP- 13587, Revision 1. The comparison of the RV geometry and transient conditions provides the basis for determining that the applied driving force ($J_{applied}$) in the WCAP-13587, Revision 1, analysis is applicable to the IP2 and IP3 RVs.

The applicant's response to RAI 4.2.2-2 indicated (1) that the IP2 RV beltline plate material was SA-302, Grade B modified (ASME Code Case 1339); (2) that the inside diameter was the same as that used in the WCAP-13587, Revision 1, analyses and the nominal wall thickness (8.625 inches) for the IP2 RV is greater than the values used in the WCAP-13587, Revision 1, analyses; (3) the cooldown rate for the IP2 RV (note: Technical Specification Figure 3.4.3-2, License Amendment No. 238, limits the maximum cooldown rate for IP2 to 100 °Fahrenheit per hour (°F/hr)) which is the same cooldown rate (100 °F/hr) used to evaluate ASME Code Service Loading A and B conditions that was evaluated in WCAP-13587, Revision 1; and (4) the

analyses in Chapter 14 of the final safety analysis report for IP2 are bounded by the conditions for the ASME Code Service Loading C and D conditions (small steamline break for Loading C condition and large steamline break for Loading D condition) that were evaluated in WCAP-13587, Revision 1. Based upon the above comparison, the applicant indicated that the evaluation provided in WCAP-13587, Revision 1, is applicable to the IP2 RV. The applicant provided a similar analysis for the IP3 RV in a response to RAI 4.2.2-2 in a letter dated June 11, 2008, although the June 11, 2008, response does not discuss the materials in the IP3 RV. In subsequent phone calls, on July 8 and 11, 2008, the applicant confirmed that the plate materials in IP3 meet the same ASME Code case and Combustion Engineering specification as those in IP2, and that WCAP-13587, Revision 1, is applicable to the plate materials in IP3.

Since the applicant projected that (1) limiting plates B2002-3 in the IP2 RV and B2803-3 in the IP3 RV would have greater Charpy USE values (48.3 ft-lb and 49.8 ft-lb, respectively) at the end of the period of extended operation than the minimum acceptable Charpy USE value (43 ft-lb) in WCAP-13587, Revision 1, for RVs in 4-loop Westinghouse-designed plants; and (2) the evaluation provided in WCAP-13587, Revision 1, is applicable to the IP2 RV and the IP3 RV, the applicant has demonstrated that the staff's conclusions in its safety evaluation for WCAP-13587, Revision 1, are applicable to the IP2 and IP3 RVs.

Regulatory Guide 1.161, "Evaluation of Reactor Pressure Vessels with Charpy Upper-Shelf Energy Less Than 50 Ft-Lb," issued June 1995, supersedes DG-1023. In addition, 10 CFR 50.55a(b)(2), "Codes and Standards," approves the use of the 2001 Edition through the 2003 addenda of Section XI of the ASME Code. This edition and addenda of the ASME Code contains criteria for evaluating RVs with low Charpy USE values. Specifically, Appendix K, "Assessment of Reactor Vessels with Low Upper Shelf Charpy Impact Energy Levels," to Section XI of the ASME Code contains the criteria. Appendix K to Section XI of the ASME Code supersedes ASME Code Case N-512. To demonstrate that the methodology and criteria in its equivalent margins analyses for the IP2 and IP3 RVs are equivalent to the methodology and criteria in RG 1.161 and Appendix K to Section XI of the ASME Code, the applicant, in a letter dated June 11, 2008, compared the methodology and criteria in its equivalent margins analyses for the IP2 and IP3 RVs to the methodology and criteria in RG 1.161 and Appendix K to Section XI of the ASME Code. The applicant concluded that the analysis documented in WCAP-13587, Revision 1, did not deviate from the methods and formulas cited in RG 1.161 and Appendix K to Section XI of the ASME Code.

The staff compared the methods and formulas documented in WCAP-13587, Revision 1, with the methods and formulas cited in RG 1.161 and Appendix K to Section XI of the ASME Code. The formulas and methods in RG 1.161 and Appendix K to Section XI of the ASME Code are the same as those in WCAP-13587, except for the formulas for calculating the stress intensity factor from radial thermal gradients. The formulas for calculating the stress intensity factor from radial thermal gradients in WCAP-13587, Revision 1, result in higher stress intensity factors than the formulas in RG 1.161 and Appendix K to Section XI of the ASME Code. Since the formulas in WCAP-13587, Revision 1, result in conservative values of stress intensity factors, the results from the analysis in WCAP-13587, Revision 1, will satisfy RG 1.161 and Appendix K to Section XI of the ASME Code.

Since the limiting plates in the IP2 and IP3 RVs were projected to have greater Charpy USE values at the end of the period of extended operation than the minimum acceptable Charpy USE values in WCAP-13587, Revision 1, and the results from the analysis in WCAP-13587,

Revision 1, will satisfy RG 1.161 and Appendix K to Section XI of the ASME Code, the applicant has demonstrated that the IP2 and IP3 RVs will have margins of safety against fracture equivalent to those required by Appendix G to Section XI of the ASME Code and will satisfy the requirements of Section IV.A.1.a of Appendix G to 10 CFR Part 50 through the end of the period of extended operation.

4.2.2.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of Charpy USE in LRA Sections A.2.2.1.3 and A.3.2.1.3, as amended by letter dated January 17, 2008. On the basis of its review of the UFSAR supplement, the staff has determined that the summary description of the applicant's actions to address Charpy USE is adequate.

4.2.2.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for Charpy USE, the analyses have been projected to the end of the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.2.3 Pressure-Temperature Limits

4.2.3.1 Summary of Technical Information in the Application

LRA Section 4.2.3 summarizes the evaluation of P-T limits for the period of extended operation. Appendix G to 10 CFR Part 50 requires the applicant to maintain reactor pressure vessel operation within P-T limits established by calculations that utilize the materials and fluence data from the unit-specific Reactor Surveillance Capsule Program. Normally, the P-T limits calculated for several years into the future remain valid for an established period of time.

IP2 technical specifications provide P-T limits valid through 25 EFPYs, and IP3 technical specifications provide P-T limits valid through 34 EFPYs, both of which include the effects of the stretch power uprates that were approved on October 27, 2004 for IP2 (ADAMS Accession No. ML042960007), and on March 24, 2005 for IP3 (ADAMS Accession No. ML050600380). At present, plate B2803-3 (initial RT_{NDT} of 74 °F) restricts operation in the 150-250 °F range.

The applicant stated that the P-T limit curve updates will continue, as required by 10 CFR Part 50, Appendix G, or as operational needs dictate, to ensure that operational limits remain valid through the period of extended operation. Additional P-T limit analysis is not required at this time. Maintenance of the P-T limit curves in accordance with 10 CFR Part 50, Appendix G, ensures adequate management of the effects of aging on intended function(s) for the period of extended operation.

4.2.3.2 Staff Evaluation

The staff reviewed LRA Section 4.2.3 to verify that, pursuant to 10 CFR 54.21(c)(1)(iii), the effects of aging on the intended function(s) will be adequately managed for the period of

extended operation. Since P-T limit curves are periodically updated in accordance with 10 CFR Part 50, Appendix G, and the license amendment process, compliance with 10 CFR Part 50 ensures that the P-T limit curves will be adequately managed for the period of extended operation. This is acceptable.

4.2.3.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of P-T limits in LRA Sections A.2.2.1.2 and A.3.2.1.2. On the basis of its review of the UFSAR supplement, the staff has determined that the summary description of the applicant's actions to address P-T limits is adequate.

4.2.3.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for P-T limits, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.2.4 Low-Temperature Overpressure Protection Power-Operated Relief Valve Setpoints

4.2.4.1 Summary of Technical Information in the Application

LRA Section 4.2.4 summarizes the evaluation of low-temperature overpressure protection (LTOP) power-operated relief valve (PORV) setpoints for the period of extended operation. For each revision of the P-T limit curves, the applicant must reevaluate the LTOP system to determine whether its functional requirements can be met; therefore, LTOP limits are part of the calculation of P-T curves.

4.2.4.2 Staff Evaluation

The staff reviewed LRA Section 4.2.4 to verify that, pursuant to 10 CFR 54.21(c)(1)(iii), the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

The LTOP PORV setpoints are determined whenever the applicant calculates P-T limit curves. Since P-T limit curves are periodically updated in accordance with 10 CFR Part 50, Appendix G, compliance with this rule ensures that the LTOP PORV setpoints will be adequately managed for the period of extended operation.

4.2.4.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of LTOP PORV setpoints in LRA Sections A.2.2.1.2 and A.3.2.1.2. On the basis of its review of the UFSAR supplement, the staff has determined that the summary description of the applicant's actions to address LTOP PORV setpoints is adequate.

4.2.4.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for LTOP PORV setpoints, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.2.5 Pressurized Thermal Shock

4.2.5.1 Summary of Technical Information in the Application

LRA Section 4.2.5 summarizes the evaluation of PTS for the period of extended operation. In accordance with 10 CFR 50.61(b)(1), applicants must assess reference temperature for pressurized thermal shock (RT_{PTS}) projected values whenever a significant change occurs in parameters (e.g., expiration date for facility operation) affecting RT_{PTS}. Specifically, 10 CFR 50.61(b)(2) establishes a screening criterion for RT_{PTS} of 270 °F for plates, forgings, and axial welds and a screening criterion of 300 °F for circumferential welds. RG 1.99, Revision 2, provides two methods (positions) for determining RT_{PTS}. Position 1 applies to material with no surveillance data available. Position 2 applies to material with surveillance data. Calculation of RT_{PTS} values use both Positions 1 and 2 follows RG 1.99, Revision 2, Sections 1.1 and 2.1, respectively, using the copper and nickel content of beltline materials and EOL best-estimate fluence projections.

The IP2 projected 48-EFPY peak beltline neutron fluence level of 1.906×10^{19} n/cm^2 at the clad-base metal interface applies to all beltline materials except the RV axial welds, where the expected peak fluence is 1.295×10^{19} n/cm^2. All projected RT_{PTS} values are within established screening criteria at 48 EFPYs.

The applicant stated that the IP3 projected 48-EFPY peak beltline neutron fluence level of 1.560×10^{19} n/cm^2 at the clad-base metal interface applies to all beltline materials. All projected RT_{PTS} values are within established screening criteria for 48 EFPYs with the exception of plate B2803-3, which exceeds the screening criterion of 270 °F by 9.9 °F. As required by 10 CFR 50.61(b)(4), the applicant will submit a plant-specific safety analysis for plate B2803-3 to the staff 3 years before the RT_{PTS} screening criterion is reached. Alternatively, IP3 may choose to implement the revised PTS rule (10 CFR 50.61a) which, if approved, will permit the application of RG 1.99, Revision 3, to plate B2803-3, with the expected result of an acceptable through-wall crack frequency at 48 EFPYs. Therefore, the aging effects of the RT_{PTS} TLAA will be adequately managed for the period of extended operation.

4.2.5.2 Staff Evaluation

The staff reviewed LRA Section 4.2.5 to verify that, pursuant to 10 CFR 54.21(c)(1)(ii), the analyses have been projected to the end of the period of extended operation and that, pursuant to 10 CFR 54.21(c)(1)(iii), the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

As defined in 10 CFR 50.61(c)(1)(v), the RT_{PTS} value is the sum of the initial (unirradiated) reference temperature ($RT_{NDT(U)}$), the shift in reference temperature caused by neutron irradiation (ΔRT_{NDT}), and a margin term (M) to account for uncertainties. The methodology for determining the ΔRT_{NDT} and M values when no surveillance data exist is defined in 10 CFR 50.61(c)(1), while the methodology for determining the ΔRT_{NDT} and M values when surveillance data do exist is defined in 10 CFR 50.61(c)(2).

For IP2, LRA Table 4.2-3 indicates that the ΔRT_{NDT} value caused by irradiation for the intermediate shell axial welds and the lower shell axial welds in IP2 were determined using surveillance data reported in WCAP-15629, Revision 1. For IP3, LRA Table 4.2-4 indicates that the ΔRT_{NDT} caused by irradiation for the lower shell plate B2803-3 was determined using surveillance data reported by the applicant's response to Generic Letter (GL) 92-01, "Reactor Vessel Structural Integrity." These surveillance data were reported in a September 4, 1998, letter from J. Knubel (New York Power Authority). The surveillance data from IP3 are also reported in WCAP-15629, Revision 1. The neutron fluence values for the IP3 surveillance capsule that are reported in WCAP-15629, Revision 1 and in the September 4, 1998, letter have different values. Therefore, by letter dated October 29, 2008, the staff asked the applicant to provide neutron fluence values derived using a methodology that adheres to the guidance in RG 1.190, and to provide the surveillance data analysis required by 10 CFR 50.61(c)(2)(i).

By letter dated November 28, 2007, the applicant responded to the staff's RAI and stated that for IP2, the revised fluences used from the H.B. Robinson plant that are consistent with the guidance of RG 1.190 have been calculated by Westinghouse. For IP3, the applicant stated that the neutron fluence values reported in LRA Table 4.2-4 were taken from a 2003 Westinghouse calculation supporting stretch power uprate. The neutron transport and dosimetry evaluation methods used to determine the fluence in the 2003 calculation followed the guidance of RG 1.190. During a telephone call held on December 3, 2007, the NRC staff requested that Entergy provide confirmation that the referenced source of the surveillance data satisfies RG 1.190, and that the surveillance data have been used in the Pressurized Thermal Shock and Charpy USE analyses. During a telephone call held on December 4, 2007, Entergy indicated that for Indian Point Unit 3, the current neutron flux and fluence values are contained in WCAP-16251, and that for IP2, WCAP-15805 contains the surveillance data for Capsule X for H. B. Robinson, and that it will revise the RAI response to reflect the source of the data.

By letter dated January 17, 2008, the applicant revised the PTS evaluation tables for the IP2 and IP3 RVs (LRA Tables 4.2-3 for IP2 and 4.2-4 for IP3).

LRA Table 4.2-3 indicates that the RT_{PTS} values for all the IP2 RV beltline materials are below the 10 CFR 50.61 PTS screening criteria at the end of the period of extended operation. The RT_{PTS} values for intermediate shell plates B2002-1, B2002-2, and B2002-3 are calculated using surveillance data from WCAP-15629, Revision 1, Table 4. The applicant determined the ΔRT_{NDT} and M values for these plates using the methodology in RG 1.99, Revision 2, Section 2.1, and 10 CFR 50.61(c)(2). The applicant determined the ΔRT_{NDT} and M values for IP2 plate B2003-1, plate B2003-2, and intermediate-to-lower shell circumferential weld 9-042 (Linde 1092, heat number 34B009) using the methodology in RG 1.99, Revision 2, Section 1.1, and 10 CFR 50.61(c)(1) since there are no surveillance data for these materials. The applicant calculated RT_{PTS} values for the intermediate shell and lower axial shell welds using surveillance data from WCAP-15805, Table D-1. This table contains data from the IP2, IP3, and H.B. Robinson surveillance welds. Combustion Engineering fabricated the IP2 intermediate shell

axial welds, the IP2 lower axial shell welds, the IP2 surveillance weld, the IP3 surveillance weld, and the H.B. Robinson surveillance weld using Linde 1092 flux and heat number W5214 weld wire. The IP2, IP3, and H.B. Robinson surveillance welds were irradiated at different temperatures and have different amounts of copper and nickel.

After its review of the revised responses provided by the applicant in its letter dated January 17, 2008, the staff requested additional information regarding the methodology used in determining the impact of the different irradiation temperatures and different amounts of copper and nickel for the surveillance welds on the ΔRT_{NDT} and M values for the IP2 intermediate shell and lower axial shell welds. In a telephone conference call on May 7, 2008, the staff informed the applicant of the needed information. By letter dated June 11, 2008, the applicant identified the methodology used to determine the impact of the different irradiation temperatures and different amounts of copper and nickel for the surveillance welds on the ΔRT_{NDT} value for the IP2 intermediate shell and lower axial shell welds. The applicant determined the ΔRT_{NDT} value for the IP2 intermediate shell and lower axial shell welds by (1) using the ratio procedure described in Position 2.1 of RG 1.99, Revision 2, to normalize the surveillance weld chemical composition to the IP2 intermediate shell and lower axial shell welds chemical composition, and (2) using a correction factor of 1 ft-lb/°F of inlet coolant temperature. The IP2 RV operates with an inlet temperature of approximately 528 °F, the H.B. Robinson RV operates with an inlet temperature of approximately 547 °F, and the IP3 RV operates with an inlet temperature of approximately 540 °F. Therefore, the measured ΔRT_{NDT} values from the IP3 surveillance program were adjusted by adding 12 °F to each measured ΔRT_{NDT}, and the measured ΔRT_{NDT} values from the H.B. Robinson surveillance program were adjusted by adding 19 °F to each measured ΔRT_{NDT} before applying the ratio procedure. This method of determining the ΔRT_{NDT} is acceptable; the staff has previously endorsed its use, at the RPV Integrity Workshop (February 12, 1998), for normalizing surveillance data from other RVs to the chemical composition and inlet temperature of the RV being evaluated. Additionally, the staff has approved the use of the methodology on plant-specific bases.

As stated in its June 11, 2008 letter, the applicant calculated the M value for the IP2 intermediate shell and lower shell axial welds using Position 2.1 of RG 1.99, Revision 2. The staff confirmed that the surveillance data satisfy the credibility criteria in RG 1.99, Revision 2. Therefore, the M value should be determined using Position 2.1 of RG 1.99, Revision 2.

Based on the above discussion, the staff finds the applicant's responses to the RAIs acceptable. The staff finds that the IP2 PTS analyses have been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

LRA Table 4.2-4 indicates that the RT_{PTS} values for all IP3 beltline materials, except for plate B2803-3, are projected to be below the PTS screening criteria at the end of the period of extended operation, pursuant to 10 CFR 50.61. The applicant determined the ΔRT_{NDT} and M values for all beltline materials, except for plate B2803-3, using the methodology in RG 1.99, Revision 2, Section 1.1, and 10 CFR 50.61(c)(1), since there are no surveillance data for these materials. The RT_{PTS} value for plate B2803-3 was calculated using surveillance data from WCAP-16251-NP, Table 5-10. The ΔRT_{NDT} and M values for plate B2803-3 were determined using the methodology in RG 1.99, Revision 2, Section 2.1, and 10 CFR 50.61(c)(2). The RT_{PTS} value at the end of the period of extended operation for plate B2803-3 was 279.5 °F. The staff confirmed that the RT_{PTS} value for plate B2803-3 at the end of the period of extended operation was calculated in accordance with RG 1.99, Revision 2 and 10 CFR 50.61.

As indicated in 10 CFR 50.61(b)(4), each pressurized-water nuclear power reactor for which the analysis required by the PTS rule indicates that, if there is no reasonably practicable flux reduction program to prevent the RT_{PTS} value from exceeding the PTS screening criteria based on the neutron fluence at the expiration date of the operating license, the licensee shall submit a safety analysis to determine what, if any, modifications to equipment, systems, and operation are necessary to prevent potential failure of the RV as a result of postulated PTS events, if continued operation beyond the screening criterion is allowed. The analysis must be submitted at least 3 years before the RT_{PTS} value is projected to exceed the PTS screening criteria. LRA Section 4.2.5 indicates that the RT_{PTS} value for plate B2803-3 in IP3 will exceed the PTS screening criterion. Therefore, by letter dated October 29, 2007, the staff asked the applicant to identify when the RT_{PTS} value for plate B2803-3 in IP3 is projected to exceed the PTS screening criterion.

In its November 28, 2007 response to RAI 4.2.5-2, the applicant indicated the following:

> Plate B2803-3 will reach the screening criterion at approximately 37 EFPY. Using a plant capacity factor of 0.97 after 2007, IP3 will achieve 37 EFPY approximately 9 years after entering the period of extended operation.
>
> With regard to flux reduction, IP3 implemented a low-low leakage loading plan in 1986 by placing fresh fuel in the interior of the core. Flux suppressors consisting of Pyrex glass were added to eight corner locations of the core in 1995. Since 1999, the suppressor material has been unclad hafnium. These flux reduction methods have been successful. However, these methods alone will not prevent plate B2803-3 from reaching the screening criterion during the period of extended operation.
>
> Commitment No. 32 states,
>
> As required by 10 CFR 50.61(b)(4), IP3 will submit a plant-specific safety analysis for plate B2803-3 to the NRC three years prior to reaching the RT_{PTS} screening criterion. Alternatively, the site may choose to implement the revised PTS (10 CFR 50.61) rule when approved, which would permit use of Regulatory Guide 1.99, Revision 3.
>
> Application of Regulatory Guide 1.99, Revision 3 to plate B2803-3 is expected to result in an acceptable RT_{PTS} value at 48 EFPY for IP3.

As worded in the commitment, when referring to the revised PTS rule, the applicant erroneously cites the existing PTS rule. In addition, the applicant referred to the use of RG 1.99, Revision 3, which is currently not cited by the proposed revised PTS rule. By letter dated August 14, 2008, the applicant amended LRA Sections 4.2.5 and A.3.2.1.4 to remove the reference to RG 1.99, Revision 3.

Based on the above discussion, the staff finds the applicant's response to the RAI and commitment for IP3 acceptable. The applicant's commitment will ensure that the PTS-related aging effects for IP3 will be managed during the period of extended operation, pursuant to 10 CFR 54.21(c)(1)(iii).

In a letter dated September 24, 2008, the applicant stated that the RT_{PTS} values for the nozzle shell plates, nozzle-to-shell longitudinal welds, and the nozzle-to-intermediate shell circumferential weld in the IP2 and IP3 vessels would be less than 100 °F at the end of the period of extended operation. The applicant further stated that these values were determined using the methodology documented in RG 1.99, Revision 2 and in 10 CFR 50.61. Since the RT_{PTS} values are less than the screening criterion in 10 CFR 50.61(b)(2), the staff finds that these components meet the requirements of 10 CFR 50.61.

4.2.5.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of PTS in LRA Sections A.2.2.1.4, and A.3.2.1.4, as amended. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address PTS is adequate.

4.2.5.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for IP2, the PTS analyses have been projected to the end of the period of extended operation. The applicant has also demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for IP3, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3 Metal Fatigue

The applicant states in LRA Section 4.3 that fatigue analyses are potential TLAAs for Class 1 and selected non-Class 1 mechanical components. Fatigue is age-related degradation caused by cyclic stressing of a component by either mechanical or thermal stresses. Fatigue analyses are TLAAs if they meet the six defined elements pursuant to 10 CFR 54.3(a). If the analyses are based on a number of cycles estimated for the current license term, they may meet the 10 CFR 54.3(a)(3) criterion of "defined by the current operating term." The applicant evaluates the TLAA in accordance with 10 CFR 54.21(c)(1) to determine which of the following conditions are demonstrated:

- (i) The analyses remain valid for the period of extended operation;
- (ii) The analyses have been projected to the end of the period of extended operation; or
- (iii) The effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

The applicant also states that the aging management reviews (AMRs) of the integrated plant assessment (summarized in SER Section 3) identified all components as susceptible to fatigue damage. If a component has a fatigue TLAA that remains valid (10 CFR 54.21(c)(1)(i)) or is projected to cover the period of extended operation (10 CFR 54.21(c)(1)(ii)), cracking from

fatigue is not an aging effect requiring management. If the TLAA does not remain valid for the period of extended operation, cracking from fatigue is an aging effect requiring management for the analyzed component. Cracking from fatigue can be managed by various plant programs in accordance with 10 CFR 54.21(c)(1)(iii).

The applicant states that fracture mechanics analyses of flaws detected during inservice inspection (ISI) may be TLAAs for those analyses based on time-limited assumptions defined by the current operating term. When a flaw is detected during ISI, the component may be replaced, repaired, or evaluated for continued service in accordance with ASME Code, Section XI. These evaluations may show that the component is acceptable to the end of the period of extended operation with projected inservice flaw growth typically predicted based on design thermal and mechanical loading cycles.

4.3.1 Class 1 Fatigue

The applicant states in LRA Section 4.3.1 that components that are designed in accordance with ASME Code, Section III, have fatigue analyses. Current design-basis fatigue evaluations calculate cumulative usage factors (CUFs) based on design transient cycles for components or subcomponents. The current design-basis fatigue evaluations do not consider the effects of reactor water environment on fatigue life. This practice is consistent with SECY-95-245, "Completion of the Fatigue Action Plan," dated September 25, 1995, which indicates that no immediate staff or licensee action is necessary on the environmentally assisted fatigue issue before the period of extended operation for license renewal.

The applicant states that the number of cycles accrued to date has been projected to determine the numbers of cycles expected at the end of 60 years of operation. With limited exceptions (discussed below), the projected numbers of cycles for 60 years of operation do not exceed the analyzed numbers of cycles.

The Fatigue Monitoring Program (FMP) tracks and evaluates design transients and requires corrective actions if the number of analyzed transients are approached, to keep the number of transient cycles experienced by the plant within the analyzed numbers of cycles, thus keeping the component CUFs below the values calculated in the design-basis fatigue evaluations. Appendix B to the LRA provides further details on the Fatigue Monitoring Program.

IP2 cycle counts are for normal conditions, test conditions, abnormal (upset) conditions, pressurizer spray actuations, and other events. A rate per day, calculated for each event and multiplied by the days remaining to the end of the period of extended operation, projects the cycles. Rates for most transients are based on the cycles accrued to date and the time from initial operation. Some transients (e.g., reactor trips) were projected based on the IP2 1999 to 2005 operating history, because plant operating practices have changed and some of the transients occur more or less often now than early in plant life.

The applicant stated that some transients, such as reactor trips, were projected based on more recent operating history, i.e., 1999 to 2005, because its plant operating practices have changed and some of the transients occur more or less often now than they did early in plant life. The applicant further stated that there were substantially more reactor trips in the early years of operation at IP2, and that the rate of reactor trips experienced in the last six years is more representative of the rate of trips expected through the remainder of plant life. The applicant

identified the following exceptions to its use of the number of cycles accrued to date to make its 60-year projections for IP2:

> The only normal condition projecting above the analyzed number of cycles is steady state fluctuations. The projection is $1.5x10^6$ while the analyzed number is $1x10^6$. However, the value shown in Table 4.3-1 is not based on actual cycles. The value shown in Table 4.3-1 for cycles as of 10/31/1999 is a calculated value based on the assumption that the transients occur at a constant rate that results in a number of transients over 40 years of operation equal to the analyzed number of transients. Hence the projection to 60 years based on this calculated value is 1.5 times the analyzed number of transients. In accordance with the Fatigue Monitoring Program, prior to the period of extended operation, corrective actions will be taken to confirm that monitoring is not required or to establish appropriate monitoring.
>
> Feedwater cycling, a replacement steam generator design transient limited to 18,300 cycles, does not appear on Table 4.3-1. The value of 18,300 is the projected value for 40 years of steam generator operation. Since the IP2 replacement steam generators will not be in service for 40 years at the end of the period of extended operation, feedwater cycling is not expected to exceed the analyzed number of cycles.
>
> The only abnormal condition projected to exceed its monitored limit is loss of power. Enhancements related to "loss of power" cycling may be found in the Fatigue Monitoring Program, Section B.1.12.
>
> Several of the "Other Events" will exceed their analyzed numbers prior to the end of the period of extended operation. These transients apply to the charging system piping, which is evaluated and described in SER Section 4.3.3.

As indicated, for certain events that affect fatigue usage, linear projections of the actual data to the end of the period of extended operation exceed the analyzed numbers of design-basis transients; however, there is implicit margin in the conservative CUF estimates. When additional fatigue analysis is required to take advantage of the implicit margin, the Fatigue Monitoring Program will take actions before the analyzed numbers of transients are exceeded. IP2 will continue to monitor analyzed cycles under the Fatigue Monitoring Program. Enhancements to the Fatigue Monitoring Program described in LRA Appendix B address the 60-year projections.

For IP3, the applicant tracks transients of the RV, safety injection actuations, and residual heat removal (RHR) cycles. A rate per day calculated for each transient, multiplied by the days remaining to 60 years, projects the number of future cycles. Rates are based on cycles accrued to date and time from initial operation.

The numbers of plant heatups and cooldowns are from the IP3 shutdown history and shutdown summary, which show the shutdown count through 1995. IP3 used the rate from 1973 to 1995 to project shutdowns and startups, and this projection should be conservative, as improved operations have resulted in less frequent shutdowns and startups in recent years.

The IP3 60-year projections showed that the number of transients will not exceed the number of analyzed cycles before the end of the period of extended operation.

The applicant stated that the Fatigue Monitoring Program will ensure that the analyzed numbers of transients are not exceeded during the period of extended operation. Enhancements to the Fatigue Monitoring Program described in LRA Appendix B will add transients to the IP3 list of those monitored as is the case for the IP2 list.

Staff Evaluation

The staff reviewed the applicant's estimate of the number of cycles for transients for a 60-year plant operation for IP2 and IP3.

For IP2, the applicant based its projections for the period of extended operation on operating history, from 1999 through 2005 for some transients. The applicant's use of more recent data to account for changes in plant operating practices is reasonable because it provides a realistic estimate for when the cycles (after 60 years of operation) might approach the number of analyzed cycles. The staff agrees with the applicant's projection. To provide additional assurance, the applicant will continue to monitor the transients under the Fatigue Monitoring Program and take corrective action before the number of analyzed cycles is reached.

For IP3, the applicant based its projections for the period of extended operation on operating history, from 1975 through 1995. Although this approach differs from the approach used for IP2, it yields a conservative estimate for when the cycles (after 60 years of operation) might approach the number of analyzed cycles. As stated above, to provide additional assurance, the applicant will continue to monitor the transients under the Fatigue Monitoring Program and take corrective action before the number of analyzed cycles is reached.

Based on the above, the staff finds that the approaches used by the applicant to calculate the 60-year projections for each unit are reasonable.

In its review, the staff noted that the applicant used data from 1973 to 1995 to project the number of plant heatups and cooldowns from 1995 to March 31, 2006 (current cycles), rather than use actual data. As stated above, the applicant will track the number of transients under the Fatigue Monitoring Program. However, without the actual number of heatups and cooldowns from 1995 to March 31, 2006, the applicant may not be able to accurately predict when the number of analyzed cycles might be exceeded. The staff notes that changes in operating practices such as refueling (12-month refueling cycle vs. 24-month refueling cycle) would decrease the number of heatups and cooldowns experienced post 1995, which should yield a more conservative projection. Nonetheless, the applicant should have the actual data for the plant startups and shutdowns during this period of time. Therefore, the staff believes that the use of actual plant operating experience in lieu of a projection for the current number of cycles is appropriate. This was identified as Open Item 4.3-1.

By letter dated January 27, 2009, the applicant stated that the actual number of cycles for IP3 plant heatups and cooldowns was determined to be 55 cycles through March 31, 2006. The applicant further stated that based on this value, the 60-year projection approximates 109 plant heatups and 109 plant cooldowns. This information was previously provided to the staff in response to Audit Item 14, by letter dated March 24, 2008. In its response, the applicant stated

that at the time the LRA was prepared, the cycle count for plant heatups and cooldowns had only accounted the raw data through December 31, 2005, because it was readily available at the time; therefore, this information was used in the LRA. On the basis of its review, the staff finds the applicant's response acceptable because the applicant determined the accrued cycles of plant heatups and cooldowns based on actual plant data and operating experience through March 31, 2006. Therefore, Open Item 4.3-1 is closed.

4.3.1.1 Reactor Vessel

4.3.1.1.1 Summary of Technical Information in the Application

LRA Section 4.3.1.1 describes the evaluation performed for the RV. The fatigue analyses for the RV were performed in accordance with ASME Code, Section III, 1965 edition, 1966 and 1967 addenda. Tables 4.3-3 and 4.3-4 present current CUF values for the RV for IP2 and IP3, respectively. The applicant stated that these TLAA results are based on those design transients listed in LRA Tables 4.3-1 for IP2 and 4.3-2 for IP3. The applicant stated that since the projected numbers of transient cycles remain within analyzed values, the TLAAs for the RV fatigue analyses will remain valid for the period of extended operation.

4.3.1.1.2 Staff Evaluation

The staff reviewed LRA Section 4.3.1.1 to verify that, pursuant to 10 CFR 54.21(c)(1)(i), the analyses remain valid for the period of extended operation or that, pursuant to 10 CFR 54.21(c)(1)(iii), the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

During an onsite audit, the staff reviewed LRA Tables 4.3-1 and 4.3-2, which list the design transient cycles and transient cycles projected for 60 years of plant operation. The staff noted that LRA Table 4.3-1 includes IP2 design transients whose 60-year projections exceed design cycles. However, LRA Section 4.3.1.1 states, "the projected numbers of transient cycles used for reactor vessel fatigue analyses remain within analyzed values," and cites the requirements of 10 CFR 54.21(c)(1)(i) for its RV TLAA. The staff asked the applicant to justify this conclusion (Audit Item 11).

In its response, dated March 24, 2008, the applicant stated the following:

> Since the Fatigue Monitoring Program assures that the analyzed numbers of cycles are not exceeded, IPEC will clarify LRA Section 4.3.1.1 to show that the effects of fatigue will be managed by the Fatigue Monitoring Program in accordance with 10 CFR 54.21(c)(1)(iii). Section 4.3.1.1 will be revised as follows:
>
> The reactor pressure vessel (and appurtenances) fatigue analyses were performed in accordance with the requirements of ASME Boiler and Pressure Vessel Code, Section III, 1965 Edition, 1966 and 1967 addenda. (A complete listing of applicable codes is given in Tables 4.1-9 of the IP2 and IP3 UFSARs). The existing fatigue analyses of the reactor vessel are considered TLAA because they are based on numbers of cycles expected in 40 years of operation. The CUFs for the reactor pressure vessel are given in Table 4.3-3 for IP2 and

Table 4.3-4 for IP3. Design cyclic loadings and thermal conditions for the reactor pressure vessel were originally defined in the design specifications and analyzed in the original vessel stress reports. These analyses have been occasionally revised, most recently for the extended power uprate. These latest analyses are reflected in the current UFSAR tables. As described in Section 4.3.1, the projected numbers of transient cycles used for reactor vessel fatigue analyses remain within analyzed values. The effects of fatigue on the reactor vessel will be managed by the Fatigue Monitoring Program in accordance with 10 CFR 54.21(c)(1)(iii) for both IP2 and IP3.

The staff finds the applicant's response acceptable because the applicant will manage the effects of fatigue on the RV for both IP2 and IP3 by the Fatigue Monitoring Program, in accordance with 10 CFR 54.21(c)(1)(iii), rather than relying on an analysis performed in accordance with 10 CFR 54.21(c)(1)(i). SER Section 3.0.3.2.6 documents the staff's evaluation of the applicant's Fatigue Monitoring Program. The staff concludes that the applicant's aging management is consistent with the recommendations of the SRP-LR, and satisfies the applicable regulatory requirements.

4.3.1.1.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of the RV in LRA Sections A.2.2.2.1 and A.3.2.2.1. In response to the staff's question as described above, the applicant revised LRA Sections A.2.2.2.1 and A.3.2.2.1 to state that the effects of aging will be managed by the Fatigue Monitoring Program for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii). The staff verified that the applicant's amendment, dated March 24, 2008, included the changes to LRA Sections A.2.2.2.1 and A.3.2.2.1.

On the basis of its review of the UFSAR supplement, the staff finds that the summary description of the applicant's TLAA evaluation of the RV is adequate.

4.3.1.1.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for the RV, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.1.2 Reactor Vessel Internals

4.3.1.2.1 Summary of Technical Information in the Application

LRA Section 4.3.1.2 describes the evaluation performed for the reactor vessel internals. The reactor vessel internals were designed to meet the intent of ASME Code, Section III, Subsection NG. LRA Tables 4.3-5 and 4.3-6 present CUF values for the reactor vessel internals for IP2 and IP3, respectively. The applicant stated that the CUFs, based on the same transients as those for the reactor vessel, will not be exceeded in 60 years; therefore, these TLAAs remain valid for the period of extended operation.

4.3.1.2.2 Staff Evaluation

The staff reviewed LRA Section 4.3.1.2 to verify that, pursuant to 10 CFR 54.21(c)(1)(i), the analyses remain valid for the period of extended operation or that, pursuant to 10 CFR 54.21(c)(1)(iii), the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

During an onsite audit, the staff reviewed LRA Tables 4.3-5 and 4.3-6, which list the CUF values for various reactor vessel internals for IP2 and IP3, respectively. The staff noted that these CUFs were derived from the results of Indian Point stretch power uprate nuclear steam supply engineering reports (WCAP-16156-P for IP2 and WCAP-16211-P for IP3). The staff asked the applicant to explain why the CUF value (0.173) for the IP2 upper support plate differs from the CUF value (0.81) for IP3 (Audit Item 8). In its response, dated March 24, 2008, the applicant offered the following explanation:

> The IP3 analysis was a later analysis performed for the IP3 power uprate that used a different cross section of the upper support plate than the older IP2 analysis. The IP3 analysis resulted in a higher CUF of 0.81. The result of the IP3 analysis is also applicable to IP2. The LRA will be revised to change the CUF value for the IP2 upper support plate in Table 4.3-5 to 0.81.

The staff finds the applicant's response acceptable, because the later analysis was performed by the applicant using a finer cross-section model, which was a more accurate model.

In LRA Section 4.3.1.2, the applicant stated that the calculated CUFs are based on number of cycles expected during 40 years of operation and that these values will not be exceeded in 60 years; therefore, the TLAAs remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i). During the audit, the staff reviewed LRA Tables 4.3-1 and 4.3-2 which list the design transient cycles and transient cycles projected for 60 years of plant operation. The staff noted that LRA Table 4.3-1 includes IP2 design transients whose 60-year projections exceed design cycles. During an onsite audit, the staff asked the applicant to justify its conclusion that TLAAs remain valid for the period of extended operation (Audit Item 12).

In its response, dated March 24, 2008, the applicant stated that the Fatigue Monitoring Program will be relied on to ensure that the analyzed numbers of transients are not exceeded. Additionally, the applicant stated that it will clarify LRA Section 4.3.1.2 to state that the effects of fatigue will be managed by the Fatigue Monitoring Program, in accordance with 10 CFR 54.21(c)(1)(iii). In the same letter, the applicant amended LRA Section 4.3.1.2 to state that "[t]he effects of fatigue on the reactor vessel internals will be managed by the Fatigue Monitoring Program in accordance with 10 CFR 54.21(c)(1)(iii) for both IP2 and IP3."

The staff finds the applicant's response acceptable, because the applicant will manage the effects of fatigue on the RV by the Fatigue Monitoring Program for both IP2 and IP3, in accordance with 10 CFR 54.21(c)(1)(iii), rather than relying on an analysis performed in accordance with 10 CFR 54.21(c)(1)(i). SER Section 3.0.3.2.6 documents the staff's evaluation of the applicant's Fatigue Monitoring Program. The staff concludes that the applicant's aging management is consistent with the recommendations of the SRP-LR and satisfies the applicable regulatory requirements.

4.3.1.2.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of the RV in LRA Sections A.2.2.2.1 and A.3.2.2.1. In response to the staff's question, as described above, the applicant revised LRA Sections A.2.2.2.1 and A.3.2.2.1 to state that the effects of aging will be managed by the Fatigue Monitoring Program for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii). The staff verified that the applicant's amendment, dated March 24, 2008, included the changes to LRA Sections A.2.2.2.1 and A.3.2.2.1.

On the basis of its review of the UFSAR supplement, the staff finds that the summary description of the applicant's TLAA evaluation of the reactor vessel internals is adequate.

4.3.1.2.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for the reactor vessel internals, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.1.3 Pressurizer

4.3.1.3.1 Summary of Technical Information in the Application

LRA Section 4.3.1.3 describes the evaluation performed for the pressurizer. The original pressurizer stress report met the requirements of ASME Code, Section N-415.1, "Vessels Not Requiring Analysis for Cyclic Operation." LRA Tables 4.3-7 and 4.3-8 present CUF values for the pressurizer for IP2 and IP3, respectively.

The original design-basis calculations for the pressurizer did not consider the impact of pressurizer insurge/outsurge transients. The IP2 CUF of record for the pressurizer surge nozzle remains the original design stress report number of 0.264. For IP3, the applicant re-evaluated the pressurizer surge line nozzle CUF to consider insurge/outsurge during the 200 design heatups and cooldowns and revised it to 0.9612. The applicant stated that, because the cycles on which these analyses are based will not be exceeded during the period of extended operation, these TLAAs remain valid for the period of extended operation. The applicant also stated that these surge nozzles, which are required to consider the environmental effects, will be reanalyzed for license renewal.

4.3.1.3.2 Staff Evaluation

The staff reviewed LRA Section 4.3.1.3 to verify that, pursuant to 10 CFR 54.21(c)(1)(i), the analyses remain valid for the period of extended operation or that, pursuant to 10 CFR 54.21(c)(1)(iii), the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

During an onsite audit, the staff reviewed LRA Tables 4.3-1 and 4.3-2, which list the design transient cycles and transient cycles projected for 60 years of plant operation. The staff noted

that LRA Table 4.3-1 includes IP2 design transients whose 60-year projections exceed design cycles. However, LRA Section 4.3.1.1 states, "the projected numbers of transient cycles used for reactor vessel fatigue analyses remain within analyzed values," and cites the requirements of 10 CFR 54.21(c)(1)(i) for its RV TLAA. The staff asked the applicant to justify this conclusion (Audit Item 12).

In its response, dated March 24, 2008, the applicant stated the following:

> These TLAA remain valid as stated as long as the analyzed values for the relevant transients are not exceeded. Since the Fatigue Monitoring Program (FMP) is relied on to assure that the numbers of transients do not exceed the analyzed values, IPEC will credit the FMP for managing the effects of aging for the period of extended operation.
>
> LRA Sections 4.3.1.2 thru 4.3.1.8 and LRA Table 4.1-2 will be revised to state that the effects of aging will be managed by the Fatigue Monitoring Program for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

In the same letter, the applicant amended its LRA according to the above response. The staff reviewed the change and noted that the correct regulation is reflected in the LRA. On this basis, the staff finds the applicant's response acceptable.

During an onsite audit, the staff reviewed LRA Section 4.3.1.1 and noted that the applicant stated that the impact of steady-state fluctuations on pressurizer fatigue determination is "not significant." The staff asked the applicant to explain the technical basis for its statement that the steady-state oscillations do not have a significant impact on fatigue (Audit Item 7).

In its response, dated March 24, 2008, the applicant stated the following:

> ASME Section III, Article 415.1(d) states, "a temperature fluctuation shall be considered to be significant if its total algebraic range exceeds the quantity S/(2*Me*Cte) where S is the value of Sa obtained from the applicable design curve for 1E6 cycles." From Figure N-415(A) of ASME Section III, Sa for 1 E6 cycles (carbon steel) is 13000 psi. From Table N-426, the coefficient of thermal expansion, Cte, for carbon steel at 500 °F is 7.94 E-6 in/in/°F. From Figure N-427 of ASME Section III the modulus of elasticity, Me, for carbon steel of less than 0.3 percent carbon at 500 °F is 26.4 E6 psi/in/in. This results in a significant temperature change of 13000/(2 * 7.94 E-6 * 26.4 E6) for a value of 31 °F. As the steady state oscillations have an algebraic range of ±3 °F maximum, they are not significant as defined by the ASME Code.

The staff reviewed the applicant's response and noted that ±3 °F is not significant according to the ASME Code. In addition, the staff performed an independent calculation of the temperature fluctuation according to ASME Code, NB- 3222.4, to verify the applicant's calculation. On this basis, the staff finds the applicant's response acceptable.

The applicant listed CUFs for various components of the pressurizer in LRA Tables 4.3-7 and 4.3-8. These IP2 and IP3 CUF values were in general agreement with the exception of the surge nozzle. The listed CUF for the IP2 surge nozzle is 0.264, while the CUF for the IP3 surge

nozzle is 0.9612. The applicant explained that the discrepancy is because LRA Table 4.3-7 listed the CUFs of record for the IP2 pressurizer without consideration of the insurge/outsurge transients.

The applicant stated in LRA Section 4.3.1.8 that it made changes to operating procedures in response to NRC Bulletin 88-11, "Pressurizer Surge Line Thermal Stratification," dated December 20, 1988. During the onsite audit, the staff asked the applicant whether it factored the mitigation strategy into the determination of the IP3 pressurizer surge nozzle CUF of 0.9612 and how it captured the fatigue usage before the use of the modified procedures in the fatigue evaluation (Audit Item 15).

In its response, dated March 24, 2008, the applicant stated the following:

> The mitigation strategy was not factored into the determination of the IP3 pressurizer surge line nozzle CUF. The calculation that determined the CUF of 0.9612 assumed the operating conditions that existed prior to implementation of the modified operating procedures. The operating conditions before implementation of modified procedures were conservatively applied to determine both the contribution to the CUF from past operation and the contribution to the CUF due to projected future operation. The delta-T (temperature)s used in the analysis were developed from plant operating records from a number of plants. This historical delta-T information was used to represent the prior operating history of the Indian Point units, and to calculate fatigue usage due to future operation. The IP3 surge nozzle CUF of record was calculated in IP3-CALC-RCS-00568, Revision 0, issued in 1993. Prior to this calculation, the CUF of record was the 0.259 calculated in the original stress report for the pressurizer. The original stress report had no analysis of insurge/outsurge.

The staff finds the applicant's response acceptable because (1) the applicant conservatively used the delta-T, which is based on data before implementation of the modified operating procedures; and (2) the CUF for the pressurizer surge line nozzles will be recalculated by including the environmentally assisted fatigue effects, as indicated in SER Section 4.3.3.2.

During the audit, the staff also asked the applicant to discuss the modified operating procedures used to mitigate the pressurizer insurge/outsurge transients. Further, the staff asked the applicant to provide actual plant data before and after plant procedures were modified to support that these changes reduced the occurrence and severity of these transients (Audit Item 15).

In its response, dated March 24, 2008, the applicant stated the following:

> IP2 and IP3 instituted operating changes consistent with the generic Westinghouse program to address surge line thermal cycling. There were two main changes: 1) A continuous (reduced flow) pressurizer spray was established. This minimized the temperature differential between the RCS, the pressurizer, and the surge line; thereby reducing the thermal stresses associated with an insurge. 2) Startup procedures were changed to eliminate drawing and then collapsing a pressurizer bubble to run reactor coolant pumps to sweep air out of the RCS/RPV. The collapsing of this bubble early in the startup procedure

had resulted in significant insurges that have now been eliminated.

Plant procedures that were changed include 2-POP-1.1, "Plant Heatup from Cold Shutdown Condition"; 2-POP-3.3, "Plant Cooldown, Mode3 to Mode5"; 3-POP1.1, "Plant Heatup from Cold Shutdown Condition"; 3-POP-3.3, "Plant Cooldown—Hot to Cold Shutdown." Results of the changes are discussed in Interoffice Correspondence IP-DEM-01-008MC, "IP3 Pressurizer Surge Line Stratification—WR-96-6280-02." The letter notes that after procedure changes, the maximum difference between the pressurizer and surge line and the RCS was 227 °F, well within the 320 °F limit. The letter concludes that the procedure changes effectively lowered the delta °F and eliminated the insurge/outsurge transients.

As documented in the Audit Report, the staff reviewed portions of WCAP-12639 and the procedures referenced in the applicant's response. In addition, the staff reviewed the interoffice correspondence which documents the effectiveness of the applicant's procedure changes. The staff verified that the delta-Ts between the pressurizer and surge line and the reactor coolant system (RCS) were reduced after implementing the modified operating procedures. On the basis of these reviews, the staff finds the applicant's response acceptable.

During the audit, the staff reviewed LRA Section 4.3.1.3 and noted several areas that required clarification. The staff asked the applicant to clarify a typographical error on page 4.3-12 of the LRA regarding the number of steady-state oscillations that were analyzed in the stress report. In addition, the staff asked the applicant to clarify page 4.3-13 of the LRA by verifying that the original stress report only analyzed the surge and spray nozzles (Audit Item 9).

In its response, dated March 24, 2008, the applicant stated the following:

LRA Section 4.3.1.3 contains a typographical error. It should have stated 10 to the sixth power or 1E6 oscillations rather than 106 oscillations. WNET-108 clearly uses 1 E6 steady state oscillations.

The second sentence on page 4.3-13 is correct as written. However, this sentence can be misleading and Entergy will reword it as follows: "While the original stress report did not analyze the pressurizer shell, it did analyze the surge nozzle and spray nozzle. The resulting CUFs are not the CUFs of record as both the surge and spray nozzles were subsequently reevaluated for the stretch power uprates. The usage factors of record are given in Tables 4.3-7 and 4.3-8.

The staff reviewed the applicant's response as well as the basis document for LRA Section 4.3.1.3. In the same letter, the applicant amended the LRA according to the response above. The staff noted that the applicant's response is editorial and clarifying in nature; therefore, it does not change the technical content of LRA Section 4.3.1.3. On this basis, the staff finds the response acceptable.

In LRA Section 4.3.1.3, the applicant stated that the pressurizer fatigue analyses remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i). Since the results reflected in LRA Table 4.3-7 do not consider insurge/outsurge, the staff asked the applicant to

justify its conclusion that TLAAs remain valid for the period of extended operation (Audit Item 13).

In its response, dated March 24, 2008, the applicant stated the following:

> Both IP2 and IP3 surge nozzles must be re-evaluated for environmentally assisted fatigue and IPEC has committed to that reanalysis prior to the period of extended operation. That reanalysis will include not only environmental factors, but also the effects of insurge/outsurge for both units.
>
> LRA Section 4.3.1.3 will be revised to state that the effects of aging will be managed by the Fatigue Monitoring Program for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

The staff finds the applicant's response acceptable because the applicant will manage the effects of fatigue on the RV by the Fatigue Monitoring Program for both IP2 and IP3, in accordance with 10 CFR 54.21(c)(1)(iii), rather than relying on an analysis performed in accordance with 10 CFR 54.21(c)(1)(i). SER Section 3.0.3.2.6 documents the staff's evaluation of the applicant's Fatigue Monitoring Program. The staff concludes that the applicant's aging management is consistent with the recommendations of the SRP-LR and satisfies the applicable regulatory requirements.

4.3.1.3.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of the pressurizer in LRA Sections A.2.2.2.1 and A.3.2.2.1. In response to the staff's question as described above, the applicant revised LRA Sections A.2.2.2.1 and A.3.2.2.1 to state that the effects of aging will be managed by the Fatigue Monitoring Program for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii). The staff verified that the applicant's amendment, dated March 24, 2008, included the changes to LRA Sections A.2.2.2.1 and A.3.2.2.1.

On the basis of its review of the UFSAR supplement, the staff finds that the summary description of the applicant's TLAA evaluation of the pressurizer is adequate.

4.3.1.3.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for the pressurizer, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.1.4 Steam Generators

4.3.1.4.1 Summary of Technical Information in the Application

LRA Section 4.3.1.4 describes the evaluation performed for the steam generators. Both IP2 and IP3 have had their steam generators replaced, IP2 in January 2001 and IP3 in June 1989. The

replacement steam generators were analyzed for fatigue in their component stress reports and were then reevaluated for fatigue because of the power increase. LRA Tables 4.3-9 and 4.3-10 present CUF values for the steam generators for IP2 and IP3, respectively. The applicant stated that none of the design transients for steam generator fatigue analysis are projected to exceed their analyzed numbers during the period of extended operation. Therefore, the applicant stated that these usage factor calculations based on the design transients will remain valid for the period of extended operation.

4.3.1.4.2 Staff Evaluation

The staff reviewed LRA Section 4.3.1.4 to verify that, pursuant to 10 CFR 54.21(c)(1)(i), the analyses remain valid for the period of extended operation or that, pursuant to 10 CFR 54.21(c)(1)(iii), the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

The applicant listed the CUF values for various steam generator components in LRA Tables 4.3-9 and 4.3-10 for IP2 and IP3, respectively. As documented in the Audit and Review Report, the staff noted that these CUFs were derived from the results of Indian Point stretch power uprate nuclear steam supply engineering reports. The applicant stated that these usage factor calculations are based on the design discussed in LRA Section 4.3.1 and determined that the analyses remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i). During the onsite audit, the staff noted that LRA Table 4.3-1 includes IP2 design transients whose 60-year projections exceed design cycles. The staff asked the applicant to justify its conclusion that TLAAs remain valid for the period of extended operation (Audit Item 12).

In its response, dated March 24, 2008, the applicant stated that these TLAAs remain valid, as stated, as long as the analyzed values for the relevant transients are not exceeded. Since the Fatigue Monitoring Program is relied on to ensure that the numbers of transients do not exceed the analyzed values, IP2 and IP3 will credit the Fatigue Monitoring Program for managing the effects of aging for the period of extended operation. The applicant also stated that it will revise LRA Section 4.3.1.4 to state that the effects of aging will be managed by the Fatigue Monitoring Program for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii). In the same letter, the applicant revised the LRA. The staff verified that the applicant's amendment, dated March 24, 2008, included the changes to LRA Section 4.3.1.4.

The staff finds the applicant's response acceptable because the applicant will manage the effects of fatigue for the steam generator components by the Fatigue Monitoring Program for both IP2 and IP3, in accordance with 10 CFR 54.21(c)(1)(iii), rather than relying on an analysis performed in accordance with 10 CFR 54.21(c)(1)(i). SER Section 3.0.3.2.6 documents the staff's evaluation of the applicant's Fatigue Monitoring Program. The staff concludes that the applicant's aging management is consistent with the recommendations of the SRP-LR and satisfies the applicable regulatory requirements.

4.3.1.4.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of steam generators in LRA Sections A.2.2.2.1 and A.3.2.2.1. In response to the staff's question as described above, the applicant revised LRA Sections A.2.2.2.1 and A.3.2.2.1 to state that

the effects of aging will be managed by the Fatigue Monitoring Program for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii). The staff verified that the applicant's amendment, dated March 24, 2008, included the changes to LRA Sections A.2.2.2.1 and A.3.2.2.1.

On the basis of its review of the UFSAR supplement, the staff finds that the summary description of the applicant's TLAA evaluation of the steam generators is adequate.

4.3.1.4.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for steam generators, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.1.5 Reactor Coolant Pump Fatigue Analysis

4.3.1.5.1 Summary of Technical Information in the Application

LRA Section 4.3.1.5 describes the evaluation performed for the reactor coolant pump (RCP). The applicant analyzed RCPs with respect to fatigue for the stretch power uprate and after a review and demonstrated that the stresses in the RCPs remain within ASME Code allowable limits. The applicant stated that the projected numbers of significant cycles in 60 years remain below the numbers of cycles in these evaluations, based on the numbers of design cycles; thus, the TLAAs remain valid for the period of extended operation.

4.3.1.5.2 Staff Evaluation

The staff reviewed LRA Section 4.3.1.5 to verify that, pursuant to 10 CFR 54.21(c)(1)(i), the analyses remain valid for the period of extended operation or that, pursuant to 10 CFR 54.21(c)(1)(iii), the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

The applicant stated in LRA Section 4.3.1.5 that, from stretch power uprate analyses, the CUFs for the IP2 and IP3 RCP main flange bolts are 0.44 and 0.32, respectively. The applicant stated that these usage factor calculations are based on the design discussed in LRA Section 4.3.1 and determined that the analyses remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i). During an onsite audit, the staff noted that LRA Table 4.3-1 includes IP2 design transients whose 60-year projections exceed design cycles. The staff asked the applicant to justify its conclusion that the TLAAs remain valid for the period of extended operation (Audit Item 12).

In its response, dated March 24, 2008, the applicant stated that these TLAAs remain valid, as stated, as long as the analyzed values for the relevant transients are not exceeded. Since the Fatigue Monitoring Program is relied on to ensure that the numbers of transients do not exceed the analyzed values, the applicant will credit the Fatigue Monitoring Program for managing the effects of aging for the period of extended operation. The applicant also stated that it will revise LRA Section 4.3.1.5 among others, and LRA Table 4.1-2 to state that the effects of aging will

be managed by the Fatigue Monitoring Program for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii). The staff verified that the applicant's amendment, dated March 24, 2008, included the changes to LRA Section 4.3.1.5.

The staff finds the applicant's response acceptable because the applicant will manage the effects of fatigue for the RCPs by the Fatigue Monitoring Program for both IP2 and IP3, in accordance with 10 CFR 54.21(c)(1)(iii), rather than relying on an analysis performed in accordance with 10 CFR 54.21(c)(1)(i). SER Section 3.0.3.2.6 documents the staff's evaluation of the applicant's Fatigue Monitoring Program. The staff concludes that the applicant's aging management is consistent with the recommendations of the SRP-LR and satisfies the applicable regulatory requirements.

4.3.1.5.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of RCPs in LRA Sections A.2.2.2.1 and A.3.2.2.1. In response to the staff's question as described above, the applicant revised LRA Sections A.2.2.2.1 and A.3.2.2.1 to state that the effects of aging will be managed by the Fatigue Monitoring Program for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii). The staff verified that the applicant's amendment, dated March 24, 2008, included the changes to LRA Sections A.2.2.2.1 and A.3.2.2.1.

On the basis of its review of the UFSAR supplement, the staff finds that the summary description of the applicant's actions to address RCP fatigue analysis is adequate.

4.3.1.5.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for the RCP, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.1.6 Control Rod Drive Mechanisms

4.3.1.6.1 Summary of Technical Information in the Application

LRA Section 4.3.1.6 describes the evaluation performed for the control rod drive mechanisms (CRDMs). The applicant originally analyzed the CRDMs in the generic component report and then reevaluated them for the power uprate. LRA Tables 4.3-11 and 4.3-12 present CUF values for the CRDMs for IP2 and IP3, respectively. The applicant stated that the numbers of analyzed design transients in these fatigue analyses will not be exceeded in 60 years of operation and thus these TLAAs remain valid through the period of extended operation.

4.3.1.6.2 Staff Evaluation

The staff reviewed LRA Section 4.3.1.6 to verify that, pursuant to 10 CFR 54.21(c)(1)(i), the analyses remain valid for the period of extended operation or that, pursuant to 10 CFR 54.21(c)(1)(iii), the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

The applicant listed the CUF values for various CRDM components in LRA Tables 4.3-11 for IP2 and 4.3-12 for IP3. As documented in the Audit and Review Report, the staff noted that these CUFs were derived from the results of Indian Point stretch power uprate nuclear steam supply engineering reports. The applicant stated that these usage factor calculations are based on the design discussed in LRA Section 4.3.1 and determined that the analyses remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i). During an onsite audit, the staff noted that LRA Table 4.3-1 includes IP2 design transients whose 60-year projections exceed design cycles. The staff asked the applicant to justify its conclusion that TLAAs remain valid for the period of extended operation (Audit Item 12).

In its response, dated March 24, 2008, the applicant stated that these TLAAs remain valid, as stated, as long as the analyzed values for the relevant transients are not exceeded. Since the Fatigue Monitoring Program is relied on to ensure that the numbers of transients do not exceed the analyzed values, IP2 and IP3 will credit the Fatigue Monitoring Program for managing the effects of aging for the period of extended operation. The applicant also stated that it will revise LRA Section 4.3.1.6 to state that the effects of aging will be managed by the Fatigue Monitoring Program for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii). The staff verified that the applicant's amendment, dated March 24, 2008, included the changes to LRA Section 4.3.1.6.

The staff finds the applicant's response acceptable because the applicant will manage the effects of fatigue for the CRDMs by the Fatigue Monitoring Program for both IP2 and IP3, in accordance with 10 CFR 54.21(c)(1)(iii), rather than relying on an analysis performed in accordance with 10 CFR 54.21(c)(1)(i). By letter dated March 24, 2008, the applicant amended the LRA according to its above response. SER Section 3.0.3.2.6 documents the staff's evaluation of the applicant's Fatigue Monitoring Program. The staff concludes that the applicant's aging management is consistent with the recommendations of the SRP-LR and satisfies the applicable regulatory requirements.

4.3.1.6.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of the CRDMs in LRA Sections A.2.2.2.1 and A.3.2.2.1. In response to the staff's question as described above, the applicant revised LRA Sections A.2.2.2.1 and A.3.2.2.1 to state that the effects of aging will be managed by the Fatigue Monitoring Program for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii). The staff verified that the applicant's amendment, dated March 24, 2008, included the changes to LRA Sections A.2.2.2.1 and A.3.2.2.1.

On the basis of its review of the UFSAR supplement, the staff finds that the summary description of the applicant's TLAA evaluation of the CRDMs is adequate.

4.3.1.6.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for the CRDMs, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concludes that the

UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.1.7 Class 1 Heat Exchangers

4.3.1.7.1 Summary of Technical Information in the Application

LRA Section 4.3.1.7 describes the evaluation performed for the Class 1 heat exchangers. The applicant calculated a projected CUF of 0.13 expected in 60 years for the regenerative heat exchangers and stated that the TLAAs for the heat exchanger fatigue remain valid for the period of extended operation. The applicant also stated that, based on design documents, the auxiliary heat exchangers are not the limiting component in the chemical and volume control system; instead, the charging nozzles are more limiting. NUREG/CR-6260 identifies the charging nozzles as one location that requires environmental adjustments to the fatigue analysis; thus, the charging nozzles will be evaluated with the other NUREG/CR-6260 locations.

4.3.1.7.2 Staff Evaluation

The staff reviewed LRA Section 4.3.1.7 to verify that, pursuant to 10 CFR 54.21(c)(1)(i), the analyses remain valid for the period of extended operation or that, pursuant to 10 CFR 54.21(c)(1)(iii), the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

In LRA Section 4.3.1.7, the applicant stated that, with regard to fatigue, the auxiliary heat exchangers are not the limiting components in the chemical and volume control system. The charging nozzles are more limiting. During an onsite audit, the staff asked the applicant to clarify which nozzle (the nozzle in the heat exchanger or the nozzle in the RCS piping) it referred to in the statement (Audit Item 142).

In its response dated March 24, 2008, the applicant stated the following:

> WCAP-12191, Section 2.4, Conclusion 3, says the charging nozzle is limiting compared to the auxiliary heat exchangers. From WCAP-12191, Section 2.3, it is clear that the nozzles being discussed are the RCS piping nozzles (the normal nozzle in the cold leg and the alternate nozzle in the hot leg).
>
> LRA Section 4.3.1.7 will be clarified to specify that the nozzle is the nozzle at the RCS cold leg piping.

In the same letter, the applicant amended its LRA to reflect the above changes. Because the applicant clarified which charging nozzle it was referring to in the LRA, the staff finds the applicant's response acceptable.

In LRA Section 4.3.1.7, the applicant stated that the regenerative heat exchanger was the controlling heat exchanger as it relates to fatigue and that the projected 60-year CUF for the IP2 regenerative heat exchanger is 0.13. The applicant also stated that there is no plant-specific evaluation for the IP3 auxiliary heat exchangers; however, the similarity in design and operation of the two units indicate that the projected CUF results would be similar. As documented in the Audit and Review Report, the staff noted that this CUF was derived from an

evaluation report for IP2. The staff asked the applicant to justify why the IP3 heat exchanger CUF is comparable to the IP2 CUF (Audit Item 17).

In its response, dated March 24, 2008, the applicant stated the following:

> As can be seen by review of Table 4.3-1 and 4.3-2, IP2 is projected to have more cycles of heatups, cooldowns, and reactor trips than IP3, based in part on IP3 having learned lessons from the early operation of IP2. Based on these projections, it is expected that the IP2 CUF will exceed the IP3 CUF. Conservatively, assume the CUFs approximately the same. As identified in LRA Section 4.3.1.7, since the IP2 CUF is only 0.13, it follows that the IP3 CUF is also well below the limit of 1.

The staff finds the applicant's response acceptable because the applicant has explained that IP3 has incorporated lessons learned from the early operation of IP2; therefore, it is expected that the IP2 CUF will exceed the IP3 CUF. The applicant committed to include enhancements in the IP3 Fatigue Monitoring Program that will provide additional monitoring of the heat exchanger cycling (Commitment No. 6).

During the audit, the staff asked the applicant to explain why it claimed that the TLAA for the heat exchanger fatigue remains valid for the period of extended operation (Audit Item 12). In its response, dated March 24, 2008, the applicant stated the following:

> These TLAA [sic] remain valid as stated as long as the analyzed values for the relevant transients are not exceeded. Since the Fatigue Monitoring Program (FMP) is relied on to assure that the numbers of transients do not exceed the analyzed values, IPEC will credit the FMP for managing the effects of aging for the period of extended operation.

The applicant also stated that it will revise LRA Section 4.3.1.7 to state that the effects of aging will be managed by the Fatigue Monitoring Program for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii). The staff verified that the applicant's amendment, dated March 24, 2008, included the changes to LRA Section 4.3.1.7.

The staff finds the applicant's response acceptable, because the applicant will manage the effects of fatigue on the Class 1 heat exchangers for both IP2 and IP3 by the Fatigue Monitoring Program, in accordance with 10 CFR 54.21(c)(1)(iii), rather than relying on an analysis performed in accordance with 10 CFR 54.21(c)(1)(i). SER Section 3.0.3.2.6 documents the staff's evaluation of the applicant's Fatigue Monitoring Program. The staff concluded that the applicant's AMP satisfies the criteria in the SRP-LR and satisfies the applicable regulatory requirements.

4.3.1.7.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of Class 1 heat exchangers in LRA Sections A.2.2.2.1 and A.3.2.2.1. In response to the staff's question as described above, the applicant revised LRA Sections A.2.2.2.1 and A.3.2.2.1 to state that the effects of aging will be managed by the Fatigue Monitoring Program for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii). The staff verified that the

applicant's amendment dated March 24, 2008, included the changes to LRA Sections A.2.2.2.1 and A.3.2.2.1.

On the basis of its review of the UFSAR supplement, the staff finds that the summary description of the applicant's TLAA evaluation of the Class 1 heat exchangers is adequate.

4.3.1.7.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for Class 1 heat exchangers, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.1.8 Class 1 Piping and Components

4.3.1.8.1 Summary of Technical Information in the Application

LRA Section 4.3.1.8 describes the evaluation performed for Class 1 piping and components. The following components were a part of the evaluation:

- American National Standards Institute (ANSI) B31.1 piping
- pressurizer surge line piping
- thermowells
- charging system piping
- IP2 Loop 3 accumulator nozzle

The applicant evaluated projected thermal cycles for 60 years of plant operation for both IP2 and IP3 ANSI B31.1 piping. The applicant determined that the maximum IP2 and IP3 surge line piping CUF occurred at the pipe side of the pressurizer nozzle safe-end with a value of 0.60. Thermowells associated with the pressurizers that are based on 200 heatup and cooldown cycles, and identified by Westinghouse, produced CUF values of 0.021. The charging system piping for both IP2 and IP3 will be analyzed, taking into account environmental adjustments in LRA Section 4.3.3, because it is a NUREG/CR-6260 location. The applicant performed a fatigue analyses on the IP2 Loop 3 accumulator nozzle to justify continued operation without a thermal sleeve.

4.3.1.8.2 Staff Evaluation

The staff reviewed LRA Section 4.3.1.8 to verify that, pursuant to 10 CFR 54.21(c)(1)(i), the analyses remain valid for the period of extended operation or that, pursuant to 10 CFR 54.21(c)(1)(iii), the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

During an onsite audit, the staff reviewed LRA Section 4.3.1.8 and noted that the applicant referenced both ANSI B31.1 and United States of America Standard (USAS) B31.1. The staff asked the applicant to explain why it was not consistent when referencing this code (Audit Item 143).

In its response, dated March 24, 2008, the applicant stated the following:

> Throughout the evolution of this code, the fatigue analysis requirements have remained fundamentally the same, and fundamentally different from ASME Section III fatigue analysis requirements. As the intention here is only to separate B31.1 fatigue analyses from Section III analyses, the distinction between ASA—USAS—ANSI—ASME is not critical to the discussion. Consequently, the LRA will be amended as follows. The discussion above will be added to the LRA Section 4.3.1.8. The title of the first subsection of LRA Section 4.2.1.8 will be changed to "B31.1 Piping." In addition, all reference to B31.1 in the remainder of the LRA will be changed to "B31.1" with no prefix.

In a letter dated March 24, 2008, the applicant amended the LRA to reflect the above changes. Because the LRA now reflects a consistent code, the staff finds the applicant's response acceptable.

During the audit, the staff reviewed LRA Section 4.3.1.8 and noted that the applicant stated, "The IP2 charging system piping failure analyses determined the limiting CUF for the charging nozzle as 0.99 for number of analyzed transients shown in the last nine entries in Table 4.3.1." The staff asked the applicant to explain the conservatism behind projecting no transient conditions for "the charging nozzle flow shutoff with delayed return to service" (Audit Item 102).

In its response, dated March 24, 2008, the applicant stated the following:

> The conservatism is in the ASME fatigue curves, which are drawn well below the experimental points where cracking actually occurred. There is no specific conservatism in the assumption of zero cycles of this one particular transient, "charging flow shutoff with delayed return to service"; however, conservatism does exist in the analysis from other numbers of transient cycles being less than the analyzed values.
>
> WCAP-12191, Revision 3, "Transient and Fatigue Cycle Monitoring Program Transient History Evaluation Report for Indian Point Unit 2—Addendum 1" provides the basis for the IP2 transient cycles that are tracked in procedure 2-PT-2Y015. Table 2.3-3 of WCAP-12191, indicates the projected number of cycles based on the detailed review of actual plant data through 10/31/99, and shows this projection results in an acceptable CUF.
>
> WCAP-12191, Revisions 2 had 5, analyzed cycles of charging flow shutoff with delayed return to power. Revision 3 modified the analyzed numbers of cycles based on operating history. While the analyzed number for charging flow shutoff with delayed return to power was reduced to 0, the analyzed numbers for other events were increased.

The staff reviewed the applicant's response and noted that the applicant justified its no-transient condition for "charging flow shutoff with delayed return to service" by increasing the analyzed numbers for other events. The staff reviewed the applicant's Fatigue Monitoring Program, which tracks cycles such as charging flow shutoff with delayed return to service, and

noted that this program includes a periodic assessment of the number of accumulated cycles. The program takes corrective action if any transient approaches its number of analyzed cycles, which may include an update of the fatigue usage calculation. The staff noted that the Fatigue Monitoring Program will update the CUF for the charging nozzle if a charging flow shutoff with delayed transient occurs. Therefore, the staff finds the applicant's response acceptable.

The staff noted that the applicant justified its zero projection for letdown flow shutoff with delayed return to service and charging flow shutoff with prompt return to service by pointing out that the projected value is not used to calculate the CUF. The staff noted that the Fatigue Monitoring Program will update the CUF if the projected value exceeds analyzed cycles. In addition, the applicant explained in its response to Audit Question 102 that it will rely on the Fatigue Monitoring Program to manage the effects of aging from fatigue. Since the applicant will monitor the number of cycles and will take the required action if the analyzed numbers are approached, the projected numbers of cycles, standing alone, are therefore not important. On this basis, the staff finds the applicant's response acceptable.

During the audit, the staff reviewed LRA Section 4.3.1.8 and noted that an analysis was done specifically for the IP2 Loop 3 accumulator nozzle and not for the other accumulator nozzles for IP2 and IP3. The staff asked the applicant to explain, in detail, why it conducted an analysis specifically for the IP2 Loop 3 accumulator nozzle (Audit Item 117).

In its response, dated March 24, 2008, the applicant stated the following:

> As stated in LRA Section 4.3.1.8, these nozzles were designed and built to USAS B31.1 and did not require the calculation of a CUF. However, after a period of operation, IP2 discovered that the Loop 3 accumulator nozzle thermal sleeve was no longer in place. IP2 performed a fatigue analysis of this nozzle (without a thermal sleeve) to show that it was acceptable for service in that condition. The analysis was done specifically for this one nozzle and does not apply to the remaining nozzles as the thermal sleeves remain in place.

The applicant explained satisfactorily why it only included the IP2 Loop 3 accumulator nozzle discussion in the LRA. The applicant explained that it conducted an analysis of the IP2 Loop 3 accumulator nozzle after the discovery that the thermal sleeve for this nozzle was no longer in place. On this basis, the staff finds the applicant's response acceptable.

During an onsite audit, the staff reviewed LRA Tables 4.3-1 and 4.3-2, which list the design transient cycles and transient cycles projected for 60 years of plant operation. The staff noted that LRA Table 4.3-1 includes IP2 design transients whose 60-year projections exceed design cycles. However, LRA Section 4.3.1.8 states that the projected numbers of transient cycles used for pressurizer surge line piping, charging system piping, and IP2 Loop 3 accumulator nozzle fatigue analyses remain within analyzed values; therefore, the TLAA remains valid through the end of the period of extended operation in accordance with the requirements of 10 CFR 54.21(c)(1)(i). The staff asked the applicant to justify this conclusion (Audit Item 12).

In its response, dated March 24, 2008, the applicant stated the following:

> LRA Sections 4.3.1.2 thru 4.3.1.8 and LRA Table 4.1-2 will be revised to state that the effects of aging will be managed by the Fatigue Monitoring Program for

the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

In a letter dated March 24, 2008, the applicant amended its LRA in accordance with the above response. The staff reviewed the change and noted that the correction stated is reflected in the LRA.

The staff finds the applicant's response acceptable, because the applicant will manage the effects of fatigue on the Class 1 piping and components for both IP2 and IP3 by the Fatigue Monitoring Program, in accordance with 10 CFR 54.21(c)(1)(iii), rather than relying on an analysis performed in accordance with 10 CFR 54.21(c)(1)(i). SER Section 3.0.3.2.6 documents the staff's evaluation of the applicant's Fatigue Monitoring Program. The staff concluded that the applicant's AMP satisfies the criteria in the SRP-LR and satisfies the applicable regulatory requirements.

4.3.1.8.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of Class 1 piping and components in LRA Sections A.2.2.2.1 and A.3.2.2.1. In response to the staff's question as described above, the applicant revised LRA Sections A.2.2.2.1 and A.3.2.2.1 to state that the effects of aging will be managed by the Fatigue Monitoring Program for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii). The staff verified that the applicant's amendment, dated March 24, 2008, included the changes to LRA Sections A.2.2.2.1 and A.3.2.2.1.

On the basis of its review of the UFSAR supplement, the staff finds that the summary description of the applicant's TLAA evaluation of Class 1 piping and components is adequate.

4.3.1.8.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for Class 1 piping and components, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.2 Non-Class 1 Fatigue

4.3.2.1 Summary of Technical Information in the Application

LRA Section 4.3.2 describes the evaluation performed for non-Class 1 piping and components. The applicant performed an evaluation of the validity of the 7000-thermal-cycles assumption used in the associated fatigue analysis for 60 years of plant operation and stated that the TLAA analysis is valid for the 60 years of plant operation.

4.3.2.2 Staff Evaluation

The staff reviewed LRA Section 4.3.2 to verify that, pursuant to 10 CFR 54.21(c)(1)(i), the analyses remain valid for the period of extended operation.

During an onsite audit, the staff noted an apparent inconsistency in LRA Section 4.3.2. In the second paragraph, the applicant stated that the RHR heat exchanger is a potential TLAA, while in the fourth paragraph the applicant stated that "no fatigue analyses for these heat exchangers have been identified." The staff asked the applicant to clarify these statements (Audit Item 144).

In its response, dated March 24, 2008, the applicant stated that the assumption in LRA Section 4.3.2 that the RHR heat exchanger had a TLAA was a conservative assumption, based solely on a statement in the original equipment specification and the final safety analysis reports that the component was designed based on 200 cycles. Given that no fatigue analysis for the RHR heat exchangers has been found, the assumption that there is a potential TLAA for this component has no basis.

The staff finds the applicant's response acceptable because the applicant clarified that a fatigue analysis for the RHR heat exchangers was not identified; therefore, a TLAA is not applicable.

The applicant further stated that it will revise LRA Section 4.3.2 as follows:

> Piping and In-line Components
> The design of ASME III Code Class 2 and 3 piping systems incorporates the Code stress reduction factor for determining acceptability of piping design with respect to thermal stresses. In general, 7000 thermal cycles are assumed, allowing a stress reduction factor of 1.0 in the stress analyses. IPEC evaluated the validity of this assumption for 60 years of plant operation. The results of this evaluation indicate that the 7000 thermal cycle assumption is valid and bounding for 60 years of operation. Therefore, the pipe stress calculations are valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).
>
> Non-piping Components
> Review of potential TLAAs for IPEC non-Class 1 components identified no TLAA.

The staff determined that the plant does not operate in a cycling mode that would expose the piping to more than 7,000 cycles in 60 years. On this basis, the staff concludes that the ASME Code B31.1 and Section III, Class 2 and 3, piping analyses remain valid, in accordance with 10 CFR 54.21(c)(1)(i).

4.3.2.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of non-Class 1 fatigue in LRA Sections A.2.2.2.2 and A.3.2.2.2, as amended by letter dated March 24, 2008. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's TLAA evaluation of non-Class 1 piping and components is adequate.

4.3.2.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that, for non-Class 1 fatigue, the analyses remain valid for the period of

extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3.3 Effects of Reactor Water Environment on Fatigue Life

4.3.3.1 Summary of Technical Information in the Application

LRA Section 4.3.3 summarizes the applicant's evaluation of the effects of the RCS environment on fatigue life of piping and components under Generic Safety Issue (GSI)-190, "Fatigue Evaluation of Metal Components for 60-Year Plant Life," for the period of extended operation. The fatigue data for the ASME Code, Section III, fatigue curves result from tests performed in air at room temperature and constant strain rate. Concerns over the potential effect of elevated temperature, reactor coolant chemistry environments, and different strain rates prompted staff-sponsored research and studies. Results are documented in NUREG/CR-5999, "Interim Fatigue Design Curves for Carbon, Low-Alloy, and Austenitic Stainless Steels in LWR Environments." Subsequent research and studies, including NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components," refined the earlier study methods.

Based on NUREG/CR-6260 and the IP2 and IP3 plant design, the following component locations were shown to be the most sensitive to reactor water environmental effects:

- RV shell and lower head
- RV inlet and outlet nozzles
- pressurizer surge line (including hot leg and pressurizer nozzles)
- RCS piping charging system nozzle
- RCS piping safety injection nozzle
- RHR Class 1 piping

The applicant evaluated the limiting locations using the guidelines of the GALL Report, Volume 2, Section X.M1, which calls for following the guidance (formulas) of (1) NUREG/CR-5704, "Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels," issued April 1999, for austenitic stainless steel; and (2) NUREG/CR-6583, "Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels," issued February 1998, for carbon steel and low-alloy steel to calculate environmentally assisted fatigue correction factors (F_{en}). LRA Tables 4.3-13 (IP2) and 4.3-14 (IP3) list the environmentally adjusted CUF values for the applicant's NUREG/CR-6260 limiting locations.

4.3.3.2 Staff Evaluation

The staff reviewed LRA Section 4.3.3 to verify that, pursuant to 10 CFR 54.21(c)(1)(ii), the analyses have been projected to the end of the period of extended operation or that, pursuant to 10 CFR 54.21(c)(1)(iii), the effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

The staff reviewed LRA Section 4.3.3 against SRP-LR Section 4.3.3.2, "Generic Safety Issue." The SRP-LR recommends that license renewal applicants address GSI-190. To assess the

impact of the reactor coolant environment on a sample of critical components, the SRP-LR states that applicants should address the recommendations as follows:

(1) The critical components include, as a minimum, those selected in NUREG/CR-6260.

(2) Evaluation of the sample of critical components applied environmental correction factors to the ASME Code fatigue analyses.

(3) Formulas for calculating the environmental life correction factors are those in NUREG/CR-6583 for carbon and low-alloy steels and those in NUREG/CR-5704 for austenitic stainless steels or approved technical equivalents.

The staff reviewed LRA Section 4.3.3 and noted that, for the bottom head to shell transition, the RV inlet nozzle, and the RV outlet nozzle for IP2 and IP3, the applicant projected its analyses to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii).

As documented in the Audit Report, the staff confirmed that the CUFs for the above-mentioned locations are correct and that the applicant accounted for increases to the CUF associated with the stretch power uprate. The projected 60-year CUFs for these locations are all less than one. On this basis, the staff concludes that the analyses performed for these components were projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

The staff reviewed LRA Section 4.3.3 to verify that, pursuant to 10 CFR 54.21(c)(1)(iii), the effects of aging on the intended function(s) for IP2 and IP3 will be adequately managed for the period of extended operation in the (1) pressurizer surge line nozzle, (2) surge line piping to safe-end weld, (3) RCS piping charging system nozzle, (4) RCS piping safety injection nozzle, and (5) RHR Class 1 piping. In a letter dated June 11, 2008, the applicant amended the LRA to note that, for the bottom head to shell transition, the RV inlet nozzle and the RV outlet nozzle locations will no longer be dispositioned under the requirements of 10 CFR 54.21(c)(1)(ii). For these locations, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation, pursuant to 10 CFR 54.21(c)(1)(iii).

During an onsite audit, the staff reviewed LRA Section 4.3.3 and noted that LRA Tables 4.3-13 (IP2) and 4.3-14 (IP3) indicate that some of the listed NUREG/CR-6260 locations with environmentally adjusted CUFs are projected to exceed a value of one during the period of extended operation. The staff also noted that several locations currently do not have an environmentally adjusted CUF. These include two components from LRA Table 4.3-13 (IP2)—the RCS piping safety injection nozzle and the RHR Class 1 piping—and three components from LRA Table 4.3-14 (IP3)—the RCS piping charging system nozzle, RCS piping safety injection nozzle, and RHR Class 1 piping. The staff asked the applicant to explain why the number of components between the IP2 and IP3 without environmentally adjusted CUFs differ. The staff also noted that, on LRA pages 4.3-22 and 4.3-23, the applicant provided a corrective action plan to address the environmentally assisted fatigue issue before the calculated CUF exceeds a value of one. The staff asked the applicant to confirm that the fatigue usage factors will be developed for the locations noted in LRA Tables 4.3-13 and 4.3-14 and to commit to a corrective action plan.

In a letter dated January 22, 2008, the applicant submitted LRA Amendment 2. The applicant revised the list of TLAA resolution options in LRA Tables 4.1-1 (IP2) and 4.1-2 (IP3). For the

TLAA entitled, "Effects of Reactor Water Environment on Fatigue Life," the applicant stated that it will use an aging management program (AMP) to manage this aging effect, in accordance with 10 CFR 54.21(c)(1)(iii). The applicant also provided revised corrective actions in LRA Amendment 2. The applicant confirmed that the fatigue usage factors will be developed for the locations identified in LRA Tables 4.3-13 and 4.3-14 and committed to a corrective action plan (Commitment 33).

In LRA Amendment 2, the applicant also provided additional information on the Fatigue Monitoring Program. Originally, the applicant's Fatigue Monitoring Program took an exception for "detection of aging effects," which indicates that the applicant would not perform periodic updates of fatigue usage calculations. As stated in Commitment 33, the applicant's Fatigue Monitoring Program includes the assessment of the impact of the reactor water environment on critical components, as identified in NUREG/CR-6260. By letter dated June 11, 2008, the applicant amended the LRA and removed the above mentioned exception. The staff notes that removal of the exception makes the Fatigue Monitoring Program consistent with the GALL Report AMP X.M1. SER Section 3.0.3.2.6 documents the staff's evaluation of the applicant's Fatigue Monitoring Program. The staff concluded that the applicant's AMP satisfies the criteria in the SRP-LR and applicable regulatory requirements.

During the onsite audit, the staff questioned the applicant as to why a difference exists between IP2 and IP3 in terms of the number of components without environmentally adjusted CUFs (Audit Item 116). In its response, dated March 24, 2008, the applicant stated the following:

> Neither unit (IP2 nor IP3) had CUF's for three locations (the charging systems nozzle, the safety injection nozzle, or the RHR Class 1 piping) as part of the original design. All of these locations were built to USAS B31.1 rather than ASME III.
>
> After a period of operation, IP2 noted that they were using the charging system nozzle at a higher rate than recommended by the OEM. (i.e., they weren't using the alternate charging nozzle as frequently as was recommended.) Consequently, IP2 performed a fatigue analysis of the charging nozzle to assess the effect of this operation. The result of that analysis is quoted in LRA Table 4.3-13.
>
> IP3 did not perform such a calculation and they therefore have no corresponding CUF in Table 4.3-14.

The staff has reviewed the applicant's description of the differences in operating history between IP2 and IP3, and finds the applicant's explanation of these differences and the resulting impact on the number of affected components to be acceptable. The difference in operating histories between IP2 and IP3 contributed to the difference between the IP2 and IP3 charging system nozzles, as presented in LRA Tables 4.3-13 and 4.3-14.

As documented in the Audit Report, the staff reviewed the applicant's calculation for the F_{en}. The staff noted that, for low-alloy steel, a value of 0.0 for the input of dissolved oxygen was used in NUREG/CR-6583, Equation 6.5b. The staff noted that Entergy maintains a dissolved oxygen content of less than or equal to 0.005 parts per million (ppm) during power operation, in accordance with its operating procedure. This dissolved oxygen content is less than 0.05 ppm,

which is the limit, defined in NUREG/CR-6583, Equation 5.5c. Therefore, the value of 0.0 for the input of dissolved oxygen is appropriate in NUREG/CR-6583, Equation 6.5b. In RAI 4.3.1.8-1, dated April 18, 2008, the staff asked the applicant to describe how other various environmental effects are factored into the calculation of the CUF using F_{en} values.

In its response, dated May 16, 2008, the applicant provided the equations used for calculating F_{en} and the factors that can affect the F_{en} value. Based on its review of the applicant's response, the staff finds that for low-alloy steel it is appropriate to eliminate the sulfur content, temperature, and strain rate from NUREG/CR-6583, Equation 6.5b, based on the value obtained from the dissolved oxygen content maintained at IP2 and IP3. For stainless steel, the staff observed that the applicant used the maximum F_{en} value of 15.35 for the material temperature, strain rate, and dissolved oxygen content. Based on the staff's review of the applicant's F_{en} calculation and its response to RAI 4.3.1.8-1, the staff confirms that the applicant has conservatively calculated the F_{en} value for austenitic stainless steel, in accordance with the guidance in NUREG/CR-5704, and appropriately calculated the F_{en} value for low-alloy steel pursuant to guidance in NUREG/CR-6583.

Based on its review discussed above, the staff concludes that the applicant correctly accounted for the different environmental factors that are inputs in calculating the F_{en} factor for low-alloy steel and used a conservative value of F_{en} for austenitic stainless steel. Therefore, the staff finds that the applicant's F_{en} values were calculated appropriately. The staff's concern described in RAI 4.3.1.8-1 is resolved.

As documented in the Audit Report, the staff reviewed the applicant's basis documents. The staff noted that these documents did not list the alert values that trigger the initiation of corrective actions for the Fatigue Monitoring Program. The staff asked the applicant to identify the alert values (Audit Item 119).

In its response, dated March 24, 2008, the applicant stated the following:

> IPEC Procedure 2-PT-2Y15 calculates "alert levels" by adding twice the number of cycles that occurred in the last fuel cycle to the total number of cycles to date. Corrective action is initiated if this alert level exceeds the number of analyzed transients.
>
> In other words, if the number of cycles is projected to remain at or below the analyzed level for 2 additional fuel cycles, no corrective action is required.

As documented in the Audit Report, the staff reviewed the applicant's procedure on site and confirmed how the alert level is calculated.

In RAI 4.3.1.8-2, dated April 18, 2008, the staff asked the applicant to further explain its corrective actions and the frequency of such actions, if the alert level is approached. In its response, dated May 16, 2008, the applicant explained that the frequency of updates for the counting of plant transients will be at least once each operating cycle, and these updates determine if design transients may be exceeded before the next update. The applicant also stated that corrective actions will be taken before the analyzed transient cycles are exceeded.

The staff finds the applicant's response acceptable because the applicant will perform periodic

updates on the number of plant transients. This will ensure that design transients will not be exceeded and will allow adequate time for the applicant to initiate corrective actions based on the calculated alert level from the applicant's procedure. These corrective actions include further reanalysis or repair or replacement of the affected components. The staff also finds the applicant's response acceptable because the applicant will include new or updated CUF calculations, as appropriate, for all NUREG/CR-6260 locations identified in LRA Tables 4.3-13 and 4.3-14 as part of the Fatigue Monitoring Program. In addition, the staff finds that the applicant will monitor the number of cycles that occur and ensure that they do not exceed the analyzed number of transients. The staff's concern described in RAI 4.3.1.8-2 is resolved.

During the audit, the staff reviewed LRA Section 4.3.3 and noted that the applicant made a commitment on LRA page 4.3-22 to reanalyze the pressurizer fatigue analysis. As stated in the LRA, the IP2 pressurizer surge nozzle has an environmentally adjusted CUF less than 1.0, while the IP3 pressurizer surge nozzle has an environmentally adjusted CUF of greater than 1.0. This is because the IP3 surge nozzle calculation includes the effects of the insurges/outsurges seen by these nozzles, while the IP2 analysis does not include these effects. The applicant stated that it will re-analyze the pressurizer surge line nozzle for both units to include insurge/outsurge and environmental effects. The staff asked the applicant if there was an official commitment made to perform this reanalysis. In its response, dated January 22, 2008, the applicant stated that the pressurizer reanalysis is included in Commitment 33. On the basis that the applicant has committed to performing the pressurizer fatigue reanalysis, the staff finds the response acceptable (Commitment 33).

During the audit, the staff reviewed LRA Section 4.3.3 and noted that the applicant misquotes NUREG/CR-6260 in LRA page 4.3-21, third paragraph, as having fatigue curves incorporating environmental effects and incorrectly references NUREG/CR-6260 in LRA page 4.3-22, third paragraph. The staff asked the applicant to clarify its statements in both instances (Audit Item 147).

In its response, dated March 24, 2008, the applicant stated the following:

> The LRA paragraph will be revised to read as follows. "NUREG/CR-6260 identified locations of interest for consideration of environmental effects in several plant designs. Section 5.5 of NUREG/CR-6260 identified the following component locations to be evaluated for the environmental effects on fatigue for IPEC vintage Westinghouse plants. These locations and the subsequent calculations are directly relevant to IPEC.

In the same letter, the applicant amended LRA Section 4.3.3 as described above. The staff finds the applicant's response acceptable, because the applicant amended LRA page 4.3-21 to correct its discussion of NUREG/CR-6260 statements.

In LRA Section 4.3.3, the applicant stated that at least 2 years prior to entering the period of extended operation, for the locations identified in NUREG/CR-6260 for Westinghouse PWRs such as IP2 and IP3, it would refine the fatigue analyses, manage the effects of aging, or repair or replace the affected locations before exceeding a CUF of 1.0. The staff noted during the audit that it was unclear as to which environmental-assisted fatigue plant-specific locations Entergy would implement one of the above mentioned options. In response to the staff's

question, the applicant amended the LRA by letter dated January 22, 2008. The revised paragraph now reads as follows:

> At least 2 years prior to entering the period of extended operation, for the locations identified in LRA Table 4.3-13 (IP2) and LRA Table 4.3-14 (IP3), under the Fatigue Monitoring Program, IP2 and IP3 will implement one or more of the following.
>
> (1) Consistent with the Fatigue Monitoring Program, Detection of Aging Effects, update the fatigue usage calculations using refined the fatigue analyses to determine valid CUFs less than 1.0 when accounting for the effects of reactor water environment. This includes applying the appropriate F_{en} factors to valid CUFs determined in accordance with one of the following.
>
> For locations in LRA Table 4.3-13 (IP2) and LRA Table 4.3-14 (IP3) with existing fatigue analysis valid for the period of extended operation, use the existing CUF.
>
> Additional plant-specific locations with a valid CUF may be evaluated. In particular, the pressurizer lower shell will be reviewed to ensure the surge nozzle remains the limiting component.
>
> Representative CUF values from other plants, adjusted to or enveloping the IPEC plant-specific external loads may be used if demonstrated applicable to IPEC.
>
> An analysis using an NRC-approved version of the ASME code or NRC-approved alternative (e.g., NRC-approved code case) may be performed to determine a valid CUF.
>
> (2) Consistent with the Fatigue Monitoring Program, Corrective Actions, repair or replace the affected locations before exceeding a CUF of 1.0.

The staff finds the applicant's commitment acceptable because the applicant, through LRA Amendment 2, corrected the third paragraph on LRA page 4.3-22 by referencing LRA Tables 4.3-13 and 4.3-14 to clearly indicate the affected plant-specific locations instead of referencing NUREG/CR-6260. Additionally, the staff finds that this commitment is consistent with 10 CFR 54.21(c)(1)(iii).

4.3.3.3 UFSAR Supplement

In a letter dated January 22, 2008, the applicant submitted LRA Amendment 2. The applicant revised its LRA Sections A.2.2.2.3 and A.3.2.2.3 regarding the UFSAR supplement summary description of the TLAA evaluation of the effects of reactor water environment on fatigue life. On the basis of its review of the revised UFSAR supplement, the staff has determined that the summary description of the applicant's TLAA evaluation of reactor water environment on fatigue life is adequate.

4.3.3.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for the components identified in NUREG/CR-6260, the effects of aging on the intended functions will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.4 <u>Environmental Qualification of Electric Equipment</u>

The applicant's Environmental Qualification (EQ) of Electric Equipment Program is an aging management program that will manage the aging effects of EQ components with TLAAs. The TLAA of the EQ electrical components includes all long-lived, passive, and active electrical and instrumentation and control components that are important to safety and are located in a harsh environment. The harsh environments of the plant are those areas subject to environmental effects by loss-of-coolant accidents or high-energy line breaks. EQ equipment comprises safety-related equipment, nonsafety-related equipment whose failure could prevent satisfactory accomplishment of any safety-related function, and certain post-accident monitoring equipment.

As required by 10 CFR 54.21(c)(1), the applicant must provide a list of TLAAs in the LRA. The applicant shall demonstrate that:

(i) The analyses remain valid for the period of extended operation;

(iii) The analyses have been projected to the end of the period of extended operation; or

(iii) The effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

4.4.1 Summary of Technical Information in the Application

LRA Section 4.4 summarizes the evaluation of TLAAs associated with EQ of electric equipment for the period of extended operation. The applicant evaluated EQ electrical components using 10 CFR 50.49(f) qualification methods. Equipment qualification evaluations that specify a qualification duration of at least 40 years, but fewer than 60 years, are considered TLAAs for license renewal.

The applicant stated that these TLAAs have not been projected for the period of extended operation; rather, the aging effects associated with these analyses are managed by the Environmental Qualification of Electric Components Program in accordance with 10 CFR 54.21(c)(1)(iii). The EQ Program is an existing program established to meet the applicant's commitments for 10 CFR 50.49. Further, the applicant stated that the program is consistent with the GALL Report, Section X.E1, "Environmental Qualification of Electric Components."

4.4.2 Staff Evaluation

The staff reviewed LRA Section 4.4 and plant basis documents to determine whether the applicant provided adequate information to meet the requirement of 10 CFR 54.21(c)(1). For the electrical equipment identified in the EQ master list, the applicant uses 10 CFR 54.21(c)(1)(iii) in its TLAA evaluation to demonstrate that the aging effects of EQ equipment will be adequately managed during the period of extended operation. As required by 10 CFR 50.49, EQ components not qualified for the current license term are to be refurbished, replaced, or have their qualification extended before reaching the aging limits established in the evaluation. The Environmental Qualification of Electric Components Program ensures that these EQ components are maintained in accordance with their qualification bases. Aging evaluations for EQ components that specify a qualification of at least 40 years are TLAAs for license renewal.

The staff reviewed the EQ Program to determine whether it will ensure that the electrical and instrumentation and control components covered under this program will continue to perform their intended functions, consistent with the CLB during the period of extended operation.

The staff's evaluation of the components' qualification focused on how the EQ Program manages the aging effects to meet the requirements pursuant to 10 CFR 50.49.

The staff conducted an audit of the information provided in LRA Section B 1.10 and program basis documents. As documented in SER Section 3.0.3.1.4, the staff finds that the EQ Program, which the applicant stated is consistent with GALL Report, Section X.E1, is consistent with the EQ program in the GALL Report. Therefore, the staff finds that the EQ Program is capable of programmatically managing the qualified life of components within the scope of the program for license renewal. The continued implementation of the EQ Program provides reasonable assurance that the aging effects will be managed and that components within the scope of the EQ Program will continue to perform their intended functions for the period of extended operation.

4.4.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of EQ of electrical equipment in LRA Section A.2.1.9 and A.3.1.9 for IP2 and IP3, respectively. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address EQ of electric equipment is adequate.

4.4.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that, for EQ of electrical equipment, the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.5 Concrete Containment Tendon Prestress Analyses

4.5.1 Summary of Technical Information in the Application

LRA Section 4.5 states that this section is not applicable because the IP2 and IP3 containment structures do not have prestressed tendons.

4.5.2 Staff Evaluation

The containments do not have prestressed tendons; therefore, the staff finds this TLAA is not applicable.

4.5.3 UFSAR Supplement

The staff concludes that a UFSAR supplement is not required because the containment structures do not have prestressed tendons.

4.5.4 Conclusion

On the basis of its review, the staff concludes this TLAA is not applicable.

4.6 Containment Liner Plate and Penetration Fatigue Analyses

4.6.1 Summary of Technical Information in the Application

In LRA Section 4.6, the applicant described a TLAA for the IP2 containment liner plate as follows:

> In 1973, a feedwater line cracked circumferentially resulting in damage to the liner plate causing containment liner plate buckling at the penetration for feedwater line #22. No repair was required for this buckling of the liner plate.
>
> Studies were performed to evaluate the effects of fatigue on the deformed area of the liner due to predicted high strain-limited cycle loading during its projected 40-year life. The evaluation used an AEC-approved maximum strain and concluded that the strain load endurance limit of the material was 450 cycles at 7.7 percent strain. The evaluation estimated that the containment liner was likely to see 50 LOCAs (concurrent with earthquakes) at 1 percent strain, and 8 cycles from containment testing (1 pre-startup full pressure test at 6.5 percent strain and 7 cycles at 3.25 percent strain). This combines to 58 cycles at assorted strain (6.5 percent maximum strain). The evaluation conservatively projected a worst case of 60 cycles at 6.5 percent strain. As this projection was so far below the allowed 450 cycles at 7.7 percent strain, no further analysis was performed.

The applicant stated that IP2 will not experience 50 loss-of-coolant accidents (concurrent with earthquakes) in 60 years of operation. Containment pressure testing is scheduled only once every 10 years. Therefore, the number of cycles experienced will continue to be less than the 60 cycles originally assumed and well below the 450-cycle limit in 60 years of operation.

Therefore, the TLAA associated with the IP2 liner adjacent to the feedwater line #22 penetration remains valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

The applicant further indicated that no other TLAAs are associated with IP2 and IP3 containment liner plate or penetrations.

4.6.2 Staff Evaluation

The staff reviewed LRA Section 4.6 to verify that the analysis remains valid for the period of extended operation, pursuant to 10 CFR 54.21(c)(1)(i).

During an onsite audit, the staff requested additional information about the 1973 feedwater line break event that resulted in buckling of the containment liner plate (Audit Item 30), as follows:

> (a) Describe in greater detail the event that resulted in the permanent liner plate deformation. When specifically did it occur? What was identified as the root cause? How was this corrected?
>
> (b) Discuss the history of ISI of the permanently deformed liner plate, from 1973 to the present.

The applicant provided the requested information in its response to Audit Item 30, dated March 24, 2008. In response to part (a) of the question, the applicant provided the requested history and corrective actions as documented in the letter dated March 24, 2008. In response to part (b) of the staff's question, the applicant stated the following:

> General visual examinations were conducted under the Containment Inservice Inspection Program between June 2004 and November 2004 for all accessible areas of the containment liner, including penetrations and airlocks, in accordance with Table IWE-2500, Category E-A, Item E1.11.
>
> Minor surface corrosion and/or coating deterioration were observed on the penetrations. This is general surface corrosion that has not resulted in any significant loss of material.
>
> The containment leak rate test at IP2 in 2006 was completed satisfactorily.

Upon further discussion with the applicant during the onsite audit, the staff became aware that the affected area of the containment liner (1) was covered with thermal insulation shortly after the accident, (2) is considered inaccessible by the applicant, and (3) is not considered for inspection under the ASME Code, Section XI, Subsection IWE accessibility for examination requirements. Consequently, there has been no inspection of the affected liner area since shortly after the 1973 event occurred.

Although the staff does not expect significant degradation to have occurred, the applicant was requested to verify the lack of degradation with a one-time inspection in connection with the applicant's Containment Inservice Inspection Program. By letter dated August 14, 2008, the applicant committed to conduct a one-time inspection of the affected area of containment liner

before entering the period of extended operation (Commitment 35). The staff's evaluation of the Containment Inservice Inspection Program and the applicant's response to the related Audit Item 27 is documented in SER Section 3.0.3.3.2.

The staff finds that the original post-accident evaluation of allowable strain cycles will remain valid because the projected number of cycles for 60 years of operation is less than 50 cycles, as compared to an allowable number of 450 cycles. Therefore, this analysis is acceptable.

4.6.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of the containment liner plate and penetration fatigue analyses in LRA Sections A.2.2.4 and A.3.2.4. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address containment liner plate and penetration fatigue analyses is adequate.

4.6.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated that the containment liner plate and penetration fatigue analyses remain valid for the period of extended operation, pursuant to 10 CFR 54.21(c)(1)(i). The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7 Other Plant-Specific TLAAs

LRA Section 4.7 summarizes the evaluation of the following plant-specific TLAAs:

- RCP flywheel analysis
- LBB
- steam generator flow-induced vibration and tube wear

4.7.1 Reactor Coolant Pump Flywheel Analysis

4.7.1.1 Summary of Technical Information in the Application

LRA Section 4.7.1 summarizes the evaluation of the RCP flywheel analysis for the period of extended operation. The RCP motors have flywheels to increase rotational inertia, prolong pump coastdown, and ensure a prolonged primary coolant flow to the core if electrical power to the pump is lost. The aging effect of concern was identified by the applicant as fatigue crack initiation and growth in the flywheel bore keyway from stresses from the motor upon startup. RG 1.14, "Reactor Coolant Pump Flywheel Integrity," recommends periodic volumetric inspection of flywheels.

The applicant inspects the RCP flywheels at least every 20 years, as required by Technical Specifications 5.5.5 (IP2) and 5.5.6 (IP3) and in accordance with the staff-approved WCAP-15666-A, which assumes 6,000 start/stop cycles of an RCP. The 6,000 start/stop cycles is an order of magnitude beyond the analyzed number of heatup and cooldown cycles in

60 years expected at IP2 and IP3 (i.e., 200 cycles). The analyzed number of cycles is far greater than the expected number of cycles, even assuming multiple RCP starts in each startup-shutdown cycle.

The applicant states that because the 6,000 cycles that WCAP-15666-A assumes far exceeds the IP2 and IP3 cycles expected in 60 years, and because WCAP-15666-A is based on 60 rather than 40 years, the applicant's analysis does not meet the 10 CFR 54.3(a) definition for a TLAA. The applicant's analysis makes no time-limited assumptions, as defined by the current operating term or by a shorter operating term plus the period of extended operation requested in the license renewal application. Further, the applicant states that an evaluation is not applicable as the flywheel analysis is not a TLAA pursuant to 10 CFR 54.3(a)(3).

4.7.1.2 Staff Evaluation

As summarized above, the applicant stated that the 6000 pump start/stop cycles assumed in the Westinghouse WCAP-15666 analysis far exceeds the expected number of IP2 and IP3 cycles in 60 years. The applicant also stated that the analyzed number of heatup and cooldown cycles for 60 years of operation is 200 for IP2 and IP3. In RAI 4.7.1-4, dated December 21, 2007, the staff questioned the validity of comparing 6,000 cycles in the WCAP-15666 analysis to 200 cycles of heatup/cooldown at IP2 and IP3. The staff questioned the values used for IP2 and IP3, in that for each of the 200 heatup/shutdown cycles, multiple RCP startups could make the total number of cycles higher than the number that was analyzed.

By letter dated January 17, 2008, the applicant responded that, as indicated in LRA Tables 4.3-1 and 4.3-2, the analyzed number of heatup and cooldown cycles for 60 years of operation is 200 for IP2 and IP3. The analyzed number of cycles is far greater than the expected number, even if multiple RCP starts are assumed in each startup shutdown cycle. Because the 6,000 cycles assumed in the analysis far exceeds the expected cycles in 60 years, and because the analysis is based on 60 years rather than 40 years, this analysis does not meet the 10 CFR 54.3(a) criteria for a TLAA.

The applicant further stated that there may be multiple starts/stops per heatup; however, even if a conservative number of starts/stops of the limiting motor is assumed, the value is still well below 6,000 cycles. One would have to assume an unrealistic 30 starts/stops for every heatup to get to 6,000 starts for the limiting flywheel. Ten starts per heatup is a conservative estimate, and that only results in 2000 starts for 200 heatups.

The staff noted that LRA Table 4.3-1 shows that the RCP start/stop condition has 10,000 cycles. In RAI 4.7.1-2(a), dated December 21, 2007, the staff requested that the applicant clarify why the WCAP-15666 flywheel analysis did not use a 10,000-cycle RCP startup/stop condition. By letter dated January 17, 2008, the applicant responded that the 10,000 RCP starts shown in LRA Table 4.3-1 are considered for their impact on the entire RCS. This value applies to starts from any one of the four RCPs and, therefore, is not an appropriate value to use in the analysis for a single RCP motor flywheel. Heatup and cooldown cycles are limited to 200. The applicant further stated that even if 10 starts and stops for the limiting pump occur during each heatup and cooldown cycle, only 2,000 RCP cycles will result. This is well below 6,000 cycles criteria used in the Westinghouse flywheel analysis. The staff finds that the applicant's

explanation is reasonable; therefore, the staff determines that 6,000 is an acceptable number of cycles for the RCP flywheel analysis.

LRA Table 4.3-1 lists various normal, test, and abnormal conditions. Some of those conditions may affect flywheel operation and the structural integrity of the flywheel. However, the applicant only mentioned the RCP start/stop condition in WCAP-15666-A. In RAI 4.7.1-2(b), dated December 21, 2007, the staff asked whether other normal, test, and abnormal conditions in LRA Table 4.3-1 should be used in WCAP-15666-A to analyze the flywheel. By letter dated January 17, 2008, the applicant responded that RG 1.14, Revision 1, Section C, Subsection 2, provides the regulatory position for flywheel design, and those guidelines were followed in the flywheel evaluation in WCAP-15666. The staff had previously reviewed and approved WCAP-15666 as documented in a May 5, 2003, letter from Herbert N. Berkow, NRC, to Robert H. Bryan, Chairman, Westinghouse Owner's Group, "Safety Evaluation of Topical Report WCAP-15666, 'Extension of Reactor Coolant Pump Motor Flywheel Examination'" (TAC No. MB2819).

Section 2 (page 2-19) of WCAP-15666 states, "There are no significant mechanisms for inservice degradation of the flywheels, since they are isolated from the primary coolant environment...." Since the flywheels are isolated from the primary coolant environment, the remaining transients in LRA Table 4.3-1 have no effect on the flywheel operation and structural integrity.

The staff finds that the applicant has clarified that the 6,000 pump start/stop events assumed in the flywheel analysis far exceed the potential start/stop events in the plant in 60 years and that the transient conditions other than the pump start/stop events in LRA Table 4.3-1 do not apply. Therefore, the RCP flywheel analysis does not meet the definition of a TLAA as defined in 10 CFR 54.3(a); specifically, the analysis does not involve time-limited assumptions defined by the current operating term.

As stated in LRA Section 4.7.1, the applicant considered only fatigue as a degradation mechanism for crack initiation and growth. In RAI 4.7.1-1, dated December 21, 2007, the staff questioned whether stress-corrosion cracking should be considered as a potential degradation mechanism in the flywheel, especially in the bore keyway, given the potential for an adverse environment, stress conditions, and material. By letter dated January 17, 2008, the applicant responded that the flywheel is a carbon steel component exposed to indoor air. Since the flywheel operates at ambient temperature in a dry indoor air environment, cracking from stress corrosion is not a plausible aging effect.

The applicant further explained that, although cracking from stress corrosion is an aging effect considered in the AMR of those components that are within the scope of license renewal and are subject to AMR, the RCP flywheel (RCP motor) is an active component that is not subject to AMR and, therefore, is not addressed by an AMR in LRA Section 3. The staff finds that the applicant has clarified that stress-corrosion cracking is not a degradation mechanism for the RPC flywheel. The staff also confirms that, because it is an active component, the RCP flywheel is not subject to an AMR.

In LRA Section 4.7.1, the applicant stated that the RCP flywheels are inspected at least once every 20 years in accordance with WCAP-15666-A. Therefore, in RAI 4.7.1-3, dated December 21, 2007, the staff asked the applicant to discuss: (a) the inspection history, results,

method used, area/volume, and coverage; (b) future inspection plans including whether a volumetric inspection will be performed at the end of 40 years or during the extended period of operation, and if not, to discuss how the structural integrity of the flywheel can be ensured; and (c) whether the flywheel surface is painted, and if so, discuss the effectiveness of the surface or visual examination if these inspection methods were used in the past or will be used in the future.

By letter dated January 17, 2008, the applicant responded for part (a) that no recordable indications have been identified from the IP2 and IP3 RCP flywheel inspections. Further, the applicant stated that the RCP motor flywheels at IP2 and IP3 are inspected using the following approved nondestructive examination (NDE) methods.

Volumetric — The ultrasonic examinations performed include a keyway corner examination, a radial gage hole examination, and a periphery examination. In the gage hole examination, the full axial depth of the gage hole is traversed. The examination is performed at each of four gage holes. Additionally, an ultrasonic examination is performed from the periphery of the flywheel scanning toward the bore. Essentially 100 percent of the specified volume coverage is obtained.

Surface — The surface examination performed includes the bore and keyway surfaces of the flywheel using dye penetrant inspection techniques. Essentially 100 percent of the specified surface coverage is obtained.

Visual — The visual examination includes inspection of high-stress areas on all surfaces. Essentially 100 percent of the specified surface coverage is obtained.

With regard to part (b), the applicant stated that, as a result of the staff approval of WCAP-15666, IP2 and IP3 extended the inspection frequency of the RCP flywheel from once every 10 years to once every 20 years. This change occurred in 2004. Entergy will continue to inspect the RCP flywheels as described above at a frequency of at least once every 20 years through the period of extended operation. Based on the evaluations provided in WCAP-15666, which has been approved by the staff, the applicant concluded that the above inspection methods and frequency are sufficient to ensure structural integrity of the RCP flywheels through the period of extended operation. With regard to part (c), the applicant stated that some of the surface areas of the RCP flywheels are painted. However, the areas that are subject to inspection via volumetric, surface, and visual examinations are not painted. Therefore, the applicant concluded that the effectiveness of the NDE examinations performed on the RCP flywheel is not compromised.

The staff finds that the applicant has performed necessary volumetric, surface, and visual examinations of the flywheel at a frequency that was approved by the staff. Therefore, the staff finds that the examination of the flywheel is acceptable.

4.7.1.3 UFSAR Supplement

In RAI 4.7.1-5, dated December 21, 2007, the staff noted that the applicant failed to provide a summary description of its TLAA evaluation of the RCP flywheel in LRA Section A.2.2. By letter dated January 17, 2008, the applicant stated that a TLAA evaluation is not applicable because the RCP flywheel analysis is not a TLAA as defined in 10 CFR 54.3(a). The applicant explained

that because the flywheel is not susceptible to stress corrosion cracking and the number of start/stop cycles bound the projected number of cycles for 60 years, the analysis is not a TLAA. As this analysis is not a TLAA, it is not included in LRA, Appendix A.2.2. The staff finds that the RCP flywheel analysis of WCAP-15666 is applicable for 60 years of operation. Therefore, the RCP flywheel should not be considered as a TLAA and a summary description in LRA Section A.2.2 is not required.

4.7.1.4 Conclusion

On the basis of its review, the staff concludes that the RCP flywheel analyses are not TLAAs. The staff also concludes that a summary description of the TLAA evaluation in the UFSAR supplement is not needed because the RCP flywheel is not a TLAA and should not be considered for TLAA evaluation.

4.7.2 Leak before Break

4.7.2.1 Summary of Technical Information in the Application

LRA Section 4.7.2 summarizes the evaluation of LBB for the period of extended operation. LBB analyses evaluate postulated flaw growth in piping and consider the thermal aging of cast austenitic stainless steel piping and fatigue transients that drive flaw growth over the operating life of the plant. Because these two analytic considerations could be influenced by time, LBB analyses are potential TLAAs.

The IP2 structural design protects against the effects of postulated reactor coolant loop pipe ruptures. LBB analyses documented in WCAP-10931, WCAP-10977, and WCAP-10977, Supplement 1, have time-related assumptions that include cast austenitic stainless steel thermal aging and fatigue crack growth analysis.

The IP3 structural design protects against the effects of postulated reactor coolant loop pipe ruptures. LBB analyses documented in WCAP-8228, Appendix A, have time-related assumptions that include cast austenitic stainless steel thermal aging and fatigue crack growth analysis. The following two paragraphs address these assumptions.

The first analytic consideration that could be influenced by time relates to the cast austenitic stainless steel material properties in the pipe fittings. Thermal aging effect increases cast austenitic stainless steel yield strength and decreases its fracture toughness. The decrease is in proportion to the level of ferrite in the material. Thermal aging in these stainless steels continues until it reaches a saturation, or fully aged, point. The analyses used fully-aged toughness values. As the LBB evaluations for both units use saturated (fully-aged) fracture toughness properties, these analyses have no material property time-dependency and are not TLAAs.

The second analytic consideration that could be influenced by time relates to the accumulation of actual fatigue transient cycles. A fatigue crack growth analysis of the RV inlet nozzle to safe-end region determined its sensitivity to small cracks. The analysis is focused on the nozzle to safe-end connection because crack growth calculated at this location represents that of the entire primary loop.

The nozzle to safe-end connection configuration includes an SA-508 Class 2 or Class 3 stainless steel-clad nozzle connected to a stainless steel safe-end by a nickel-based alloy weld. Evaluation of crack growth from fatigue assumed the total allowable numbers of normal, upset, and test transients for the RV.

The calculated fatigue crack growth for 40 years was very small (less than 50 mils) regardless of the material evaluated. As noted in LRA Section 4.3.1, the projections for 60 years of operation indicate that the numbers of significant IP2 or IP3 transients will not exceed design-analyzed values.

4.7.2.2 Staff Evaluation

The staff has approved application of the LBB approach for the main RCS piping at IP2 and IP3 (i.e., hot leg from the RV to the RCPs, the intermediate crossover pipe, and the cold leg from the steam generators to the RV). The LBB approach has not been applied to any other systems or branch lines.

By letter dated February 23, 1989, the staff issued its safety evaluation approving the application of the LBB approach for RCS piping at IP2. The staff's approval was based on the technical basis of (1) WCAP-10977, "Technical Bases for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for Indian Point Unit 2," Original—November 1985; Revision 1—March 1986; and Revision 2—December 1986, (2) WCAP-10977, Supplement 1, "Additional Information in Support of the Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for Indian Point Unit 2," January 1989, and (3) WCAP-10931, Revision 1, "Toughness Criteria for Thermally Aged Cast Stainless Steel," July 1986.

By letter dated March 10, 1986, the staff approved the application of LBB methods for IP3 primary loop piping based on the submitted Fracture Proof Design Corporation Report 80-121, Revision 1. However, LRA Section 4.7.2 states that IP3 LBB analyses have been documented in the Westinghouse report, WCAP-8228, which was not submitted to the NRC for review. In RAIs 4.7.2-1, 4.7.2-2, and 4.7.2-4, dated December 21, 2007, the staff asked the applicant to confirm whether there are other applicable LBB analyses of record for IP3, and to provide a history and summary description of the analyses, including the parameters that were evaluated and conclusions reached for each analysis. By letter dated January 17, 2008, the applicant explained that between 1981 and 1984 it performed original LBB analyses for the IP3 primary loop piping. These analyses took into account thermal aging effects on cast stainless steel components in the IP3 primary loop. Fracture Proof Design Corporation Report 80-121, Revision 1, documents the results of the 1984 LBB analyses.

The applicant updated its LBB analyses in 1997 in support of the Steam Generator Snubbers Deactivation Program at IP3 and documented the results in WCAP-8228, Revision 1, Appendix A. Subsequently, as part of the stretch power uprate for IP3, the applicant prepared WCAP-16212, including updated LBB analyses, to ensure that the elimination of the primary loop pipe breaks continues to be justified at the uprated operating conditions. WCAP-16212 evaluated the effects of the stretch power uprate on the acceptability of the LBB status of the primary loop piping. WCAP-16212 determined that the LBB conclusions in Fracture Proof Design Corporation Report 80-121 and WCAP-8228, Revision 1, remain valid. As part of its

review of the power uprate submittal, the staff concurred with the WCAP-16212 conclusion as shown in SER Section 3.6.6.1 for the IP3 stretch power uprate dated March 24, 2005. That safety evaluation discusses further the impact of power uprate on the LBB analyses.

The potential time-limited assumptions in WCAP-8228, Revision 1, Appendix A, and WCAP-16212 involve the thermal aging of cast austenitic stainless steel and the fatigue crack growth analysis. These two assumptions are addressed below.

Thermal Aging of Cast Austenitic Stainless Steel. The RCS piping material for both IP2 and IP3 is SA 376 Type 316 forged austenitic stainless steel, while the fitting (i.e., elbows) material is SA 351 Type CF8M cast austenitic stainless steel.

The first analysis consideration in WCAP-10977 (for IP2) and WCAP-8228, Appendix A (for IP3), which could be influenced by time is the material properties of cast austenitic stainless steel used in the pipe fittings. Thermal aging causes an elevation in the yield strength of cast austenitic stainless steel and a decrease in fracture toughness due to the level of ferrite in the material. Thermal aging in these stainless steels will continue until a saturation (i.e., fully aged) point is reached. WCAP-10977 and WCAP-8228, Appendix A, address the fracture toughness properties of statically cast CF8M stainless steel. Specifically, fully aged, bounding fracture toughness values were used to conservatively calculate the fracture toughness value (J value) for the cast fittings. The IP3 LBB analysis uses the methodology of NUREG/CR-4513 and WCAP-10931 to determine saturation (fully aged) toughness values. The IP2 LBB analysis uses the methodology of WCAP-10931 to determine saturation (fully aged) toughness values. As the LBB evaluations for both units use saturated (fully aged) fracture toughness properties, these analyses do not have a material property time-dependency and are not considered a TLAA.

The pre-service (normal) and the fully aged fracture toughness values (i.e., J_{Ic}, T_{mat}, and J_{max}) for IP2 were taken from WCAP-10977, Revision 2, as the lower bound values at 600 °F. These IP2 fracture toughness values also bound the IP3 locations evaluated in WCAP-8228, Revision 1.

By letter dated May 19, 2000, Christopher I. Grimes of the NRC forwarded to Douglas J. Walters of the Nuclear Energy Institute an evaluation of thermal aging embrittlement of cast austenitic stainless steel components (ADAMS Accession No. ML003717179). In that letter, the staff provided guidance on how to manage the aging of cast austenitic stainless steel components.

LRA Section 4.7.2 does not mention any AMP to manage the cast austenitic stainless steel components in LBB piping systems. In RAI 4.7.2-5, dated December 21, 2007, the staff asked the applicant to discuss whether the cast austenitic stainless steel components in the LBB piping satisfy the guidance in the staff's May 19, 2000, letter. In its January 17, 2008, letter, the applicant responded that the AMR results for cast austenitic stainless steel components are provided in LRA Section 3. The AMR results for cast austenitic stainless steel components in LRA Section 3 agree with the staff position expressed in the May 19, 2000, letter from Christopher I. Grimes. The applicant stated that the only cast austenitic stainless steel components to which LBB has been applied are pipe fittings (elbows). These fittings will be screened based upon the molybdenum content, casting method, and ferrite content, then inspected as appropriate, in accordance with the Grimes letter. This will be performed under

AMP B.1.37, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program." This program is credited in multiple line items in LRA Tables 3.1.2-3 (IP2) and 3.1.2-3 (IP3) and, as described in LRA Section B.1.37, will be consistent with the program described in GALL Report, Section XI.M12.

The description of the program in LRA Appendix B references the Grimes letter of May 19, 2000. The staff has confirmed that LRA Section 3 does identify the thermal aging AMP to manage the cast austenitic stainless steel components and, therefore, this issue is resolved.

In RAIs 4.7.2-3 and 4.7.2-6, dated December 21, 2007, the staff asked whether thermal aging causes an increase in the yield strength of cast austenitic stainless steel. In its January 17, 2008, letter, the applicant further clarified that the yield and ultimate strength used in the LBB analysis for both IP2 and IP3 were taken as the lower bound values because this resulted in the most limiting conditions. The increase in the material yield strength was not credited in the analysis because the lower bound values bound the aged values.

The applicant stated that the mechanical properties and fracture toughness values used in the LBB analyses for both IP2 and IP3 included the most limiting values for both the pre-service and fully aged conditions. Since no additional drop in fracture toughness properties is expected once fully aged conditions are reached, these analyses are time independent and therefore bound the 60 year operating life.

The staff confirmed that the applicant used the mechanical properties and fracture toughness values that bound the 60-year operating life for the cast austenitic stainless steel components in its LBB analysis. The applicant has performed an acceptable TLAA evaluation and therefore this issue is resolved.

Fatigue Crack Growth. In its response to RAI 4.7.2-7, dated January 17, 2008, the applicant stated that the second analysis consideration which could be influenced by time is the accumulation of actual fatigue transient cycles used in WCAP-10977, Revision 2, and Supplement 1, and WCAP-8228, Appendix A. Westinghouse performed a generic fatigue crack growth analysis using the RV inlet nozzle to safe-end region to determine its sensitivity to the presence of small cracks.

The nozzle to safe-end connection was selected because crack growth calculated at this location is representative of the entire primary loop. The nozzle to safe-end connection configuration includes an SA 508 Class 2 or Class 3 stainless steel clad nozzle connected to a stainless steel safe-end by a nickel-based alloy weld (Alloy 82/182). The applicant assumed four initial flaw sizes ranging from 0.292 inches to 0.425 inches and locations with three different materials—stainless steel, SA 508 low-alloy steel, and an Inconel weld cross-section. For IP2 and IP3, the junction of the hot leg and the RV outlet nozzle is the bounding location for load and the fracture toughness associated with thermal aging occur in several pipe fittings. These are joints where the hot leg meets the steam generators and the intermediate crossover leg, and the cold leg meets the RV inlet nozzle.

The applicant used a fatigue crack growth rate law for the stainless steel clad low-alloy steel nozzle from ASME Code, Section XI. Fatigue crack growth rate laws for stainless steel and Alloy 600 in a pressurized-water reactor (PWR) environment were developed based on available industry literature. These crack growth rate laws were applied based on all normal,

upset, and test RV fatigue transients, thus resulting in projected rates of crack growth calculated in units of inches/cycle for ferritic steel, stainless steel, and Alloy 600.

The applicant's LBB analyses show that the final crack size for small stable flaws varies by location within the primary coolant system loop piping. For each limiting location the final crack size satisfies LBB acceptance criteria because adequate margin exists between the calculated leak rate and the 1 gallon per minute criterion in RG 1.45, "Guidance in Monitoring and Responding to Reactor Coolant System Leakage." The applicant concluded that there is sufficient margin between detectable leaks and large stable flaws.

In its response to RAI 4.7.2-9, dated January 17, 2008, the applicant stated that the transient conditions and associated number of cycles (for 40 years) used in the fatigue crack growth analysis are the design transients originally defined in the plant's equipment specifications and analyzed in the original component stress reports. USFAR Table 4.1-8, Revision 20, issued in 2006 for IP2, and USFAR Table 4.1-8, Revision 1, issued in 2005 for IP3, list the design transient cycles. The projected numbers of transient cycles for 60 years remain within these analyzed values. LRA Tables 4.3-1 and 4.3-2 include the design transients found in UFSAR Table 4.1-8.

The applicant stated that it did not perform fatigue growth calculations for 60 years because the projected number of cycles for 60 years is less than the numbers of cycles used in the LBB analysis. The 60-year projections for IP2 show that none of the transients that affect the nozzle inlet to safe-end fatigue analysis will exceed the analyzed cycles. The 60-year projections for IP3 show that no transient will exceed the number of analyzed cycles before the end of the period of extended operation. The applicant stated that in WCAP-10977, Table 6.1, and WCAP-8228, Table 8-2, fatigue crack growth at IP2 and IP3 for 40 years was found to be very small based on the projected transients and stress intensity factors, regardless of the material evaluated. The applicant stated that, as a result, there is reasonable assurance that the fatigue crack growth analyses presented in WCAP-10977 (IP2) and WCAP-8228 (IP3), Revision 1, Appendix A, remain valid during the period of extended operation.

The staff has determined that the fatigue crack growth calculation for the RCS piping in the LBB analyses remain valid for the period of extended operation because the 60-year projections for IP2 and IP3 show that no transient will exceed the number of analyzed cycles before the end of the period of extended operation.

Primary Water Stress-Corrosion Cracking. In RAI 4.7.2-8, dated December 21, 2007, the staff noted that PWRs have experienced primary water stress-corrosion cracking (PWSCC) in Alloy 82/182 weld material. The staff questioned how the applicant manages potential PWSCC of Alloy 82/182 weld material in LBB-approved RCS piping. In a letter dated January 17, 2008, as

corrected by letter dated November 6, 2008, the applicant identified the following LBB-approved RCS piping components that contain Alloy 82/182 weld material.

Alloy 82/182 Welds in LBB-Approved Piping at Indian Point Unit 2

Weld ID Number	Piping Identification Reactor Vessel Nozzle	Pipe Size
RPVS-21-1A	Primary Coolant Loop 21 (Outlet)	29" I.D.
RPVS-21-14A	Primary Coolant Loop 21 (Inlet)	27½" I.D.
RPVS-22-1A	Primary Coolant Loop 22 (Outlet)	29" I.D.
RPVS-22-14A	Primary Coolant Loop 22 (Inlet)	27½" I.D.
RPVS-23-1A	Primary Coolant Loop 23 (Outlet)	29" I.D.
RPVS-23-14A	Primary Coolant Loop 23 (Inlet)	27½" I.D.
RPVS-24-1A	Primary Coolant Loop 24 (Outlet)	29" I.D.
RPVS-24-14A	Primary Coolant Loop 24 (Inlet)	27½" I.D.

Alloy 82/182 Welds in LBB-Approved Piping at Indian Point Unit 3

Weld ID Number	Piping Identification Reactor Vessel Nozzle	Pipe Size
INT-1-4100-1(DM)	Primary Coolant Loop 31 (Outlet)	29" I.D.
INT-1-4100-16(DM)	Primary Coolant Loop 31 (Inlet)	27½" I.D.
INT-1-4200-1(DM)	Primary Coolant Loop 32 (Outlet)	29" I.D.
INT-1-4200-16(DM)	Primary Coolant Loop 32 (Inlet)	27½" I.D.
INT-1-4300-1(DM)	Primary Coolant Loop 33 (Outlet)	29" I.D.
INT-1-4300-16(DM)	Primary Coolant Loop 33 (Inlet)	27½" I.D.
INT-1-4400-1(DM)	Primary Coolant Loop 34 (Outlet)	29" I.D.
INT-1-4400-16(DM)	Primary Coolant Loop 34 (Inlet)	27½" I.D.

The applicant stated that these welds are routinely inspected as part of the ISI Program. The applicant volumetrically inspected the subject welds in IP2 in spring 2006 and in IP3 in fall 1999,

with no unacceptable indications. Because the applicant has inspected the subject Alloy 82/182 welds per the ISI Program, the staff's concern in the RAI is resolved.

Impact of Power Uprate on LBB Analyses. By letters dated May 22, 2003, and October 27, 2004 (ADAMS Accession Nos. ML031420375 and ML042960007, respectively), the staff approved measurement uncertainty and stretch power uprate applications for IP2. By letters dated November 26, 2002, and March 24, 2005 (ADAMS Accession Nos. ML023290636 and ML050600380, respectively), the staff approved measurement uncertainty and stretch power uprate applications for IP3. In RAI 4.7.2-10, dated December 21, 2007, the staff asked the applicant whether the results of the 40-year LBB analyses bound the conditions at the end of 60 years, in light of the power uprates. In its January 17, 2008, letter, the applicant responded that the original LBB analyses for IP2 and IP3 will remain valid during the period of extended operation because they are not "40-year analyses," but rather they are analyses based on saturated material properties and numbers of design transients that will not be exceeded in 60 years. WCAP-16156-P, "Indian Point Nuclear Generating Unit No. 2, Stretch Power Uprate NSSS Engineering Report," issued February 2004 for IP2, and WCAP-16211-P, "Power Uprate Project, Indian Point Unit 3 Power Plant, NSSS Engineering Report," issued June 2004 for IP3, address the effects of the power uprate on the original LBB analyses.

The LBB analysis for both IP2 and IP3 used a Westinghouse-proprietary methodology which the staff has previously reviewed and approved. Although the Westinghouse methodology is consistent with the methodology provided in NUREG-1061, Volume 3, these two methodologies are not exactly the same. In some cases, the Westinghouse methodology is more conservative while in other cases, the NUREG-1061, Volume 3, methodology is slightly more conservative. However, both methods provide sufficient margins of safety to ensure that leakage from a crack under normal operating loads would be detected by the existing leak detection systems and that the crack would not result in pipe failure under postulated accident loads.

The staff previously found that the original LBB analyses for IP2 and IP3 are acceptable under the power uprate conditions. The LBB analyses use material properties and transient conditions that satisfy 60 years. Therefore, the LBB analyses are acceptable for use for the extended period of operation.

On LRA page 4.7-2, the applicant asserted that the IP2 and IP3 analyses remain valid during the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i), on the basis of its evaluation of fatigue crack growth and thermal aging of cast austenitic stainless steel. In RAI 4.7.2-11, dated December 21, 2007, the staff asked the applicant to discuss whether the leakage calculations, crack stability, and capability of the reactor coolant leakage detection system in the original LBB analyses will be affected as a result of the extended period of operation. The staff questioned whether there are time-dependency parameters in the LBB calculations other than fatigue crack growth and thermal aging of cast austenitic stainless steel.

In its January 17, 2008, letter, the applicant responded that the leakage calculations for both IP2 and IP3 were based on the operating loads, the material properties, and the through-wall crack length for each of the bounding locations. Since the number of fatigue cycles analyzed bounds the period of extended operation, and since the evaluations used the fully aged fracture toughness values, the bounding flaw size and the material properties also are bounding for 60 years. The normal operating loads are unaffected by the additional 20 years of operation because the operating conditions are not changed for the period of extended operation.

Therefore, the leakage calculations performed in support of LBB for 40 years of operation remain valid for the additional 20 years of operation.

The applicant performed crack stability analyses using the most limiting fracture toughness values considering both the pre-service conditions as well as the fully aged conditions. Because no additional drop in fracture toughness properties is expected once fully aged conditions are reached, these analyses are time independent and therefore bound the 60-year operating life.

The leak detection systems for both IP2 and IP3 are based on the following instrumentation—(1) containment air radioactive particulate monitor, (2) containment air radioactive gas monitor (sensitivity variable depending on the amount of fuel clad leakage to provide radioactive gas to the coolant), (3) containment sump monitor, and (4) fan cooler unit condensate flow rate monitor. The applicant stated that the capability of the leak detection system components remains unchanged from that represented in the staff's SERs approving LBB for each unit.

The staff finds that the original LBB analyses for the RCS piping will not be affected by the additional 20 years of operation in terms of leakage calculations, leak detection system capability, and crack stability. Therefore, the LBB analyses are applicable to the extended period of operation.

4.7.2.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of LBB in LRA Sections A.2.2.5 and A.3.2.5 for IP2 and IP3, respectively. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address LBB is adequate and acceptable.

4.7.2.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that, for LBB, the analyses remain valid for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.7.3 Steam Generator Flow-Induced Vibration and Tube Wear

4.7.3.1 Summary of Technical Information in the Application

LRA Section 4.7.3 summarizes the evaluation of steam generator flow-induced vibration and tube wear for the period of extended operation. The IP2 steam generators were evaluated on the basis of flow-induced vibration (tube wear) for the power increase. The analysis of the effects of steam generator flow-induced vibration on tube wear assumed 40 years of operation. The IP2 replacement steam generators went into service in January 2000 and will have less than 40 years of service at the end of the period of extended operation (September 2033); therefore, the analysis of flow-induced vibration effects on tube wear will remain valid through the end of the period of extended operation.

The IP3 steam generators were evaluated as to flow-induced vibration on tube wear for the power increase. The maximum pre-uprate predicted tube wear was 1.3 mils. As a result of the 4.8-percent uprate, tube wear increased 87 percent. The post-uprate wear over 40 years is approximately 2.4 mils (approximately 4.9 percent through-wall wear). This amount of wear will not affect tube integrity significantly. The IP3 replacement steam generators went into service in 1989 and will have 46.5 years of service at the end of the period of extended operation (2035); therefore, this analysis is a TLAA. As tube wear is a result of time in service, it is appropriate to project the additional wear for the period of extended operation as 46.5/40 times the 40-year wear. Projected wear is 2.8 mils (approximately 5.7 percent through-wall) by the end of the period of extended operation, still well below the allowable 40-percent through-wall wear depth (20 mils); hence, tube wear during the period of extended operation will not be unacceptably high, and the IP3 tube wear TLAA has been projected to the end of the period of extended operation.

4.7.3.2 Staff Evaluation

The staff reviewed LRA Section 4.7.3, to verify that, pursuant to 10 CFR 54.21(c)(1)(i), the analyses remain valid for the period of extended operation and that, pursuant to 10 CFR 54.21(c)(1)(ii), the analyses have been projected to the end of the period of extended operation.

The IP2 replacement steam generators were installed in January of 2000. The applicant stated that the design life of the replacement steam generators extends to 2040, which exceeds the period of extended operation sought in its LRA. The applicant concludes that the steam generator flow-induced vibration analysis remains valid for the period of extended operation. In addition to a valid flow-induced vibration analysis, the IP2 steam generators are designed to minimize the potential for flow-induced vibration to occur. Steam generator tubes are supported to minimize excessive vibration which could be detrimental to their structural integrity. The impact of flow-induced vibration will most likely cause tube wear at the intersection of anti-vibration bars and the tubes. However, periodic inspections conducted in accordance with the applicant's Steam Generator Integrity Program will ensure that any potential tube wear is monitored and detected. On the basis of the information the applicant submitted, the staff concludes that the applicant has demonstrated that, pursuant to 10 CFR 54.21(c)(1)(i), the TLAA of flow-induced vibration on steam generator tubes remain valid for the period of extended operation and is therefore acceptable.

The IP3 replacement steam generators went into service in 1989 and will have 46.5 years of service at the end of the period of extended operation. The licensee projected the additional wear rate for the period of extended operation. The projected wear is well below the allowable wear depth. The staff reviewed and confirmed the licensee's analysis. In addition to a valid flow-induced vibration analysis, the IP3 steam generators are designed to minimize the potential for flow-induced vibration to occur. Steam generator tubes are supported to minimize excessive vibration which could be detrimental to their structural integrity. The impact of flow-induced vibration will most likely cause tube wear at the intersection of antivibration bars and the tubes. However, periodic inspections conducted in accordance with the applicant's Steam Generator Integrity Program will monitor and detect any potential tube wear. On the basis of the information the applicant submitted, the staff concludes that the applicant has demonstrated that, pursuant to 10 CFR 54.21(c)(1)(ii), the TLAA of flow-induced vibration on steam generator

tubes has been projected to the end of the period of extended operation and is therefore acceptable.

4.7.3.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of steam generator flow-induced vibration and tube wear in LRA Sections A.2.2.6 and A.3.2.6. On the basis of its review of the UFSAR supplement, the staff concludes that the summary description of the applicant's actions to address steam generator flow-induced vibration and tube wear is adequate.

4.7.3.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that, for IP2, the steam generator flow-induced vibration and tube wear analyses remain valid for the period of extended operation. The applicant also has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that, for IP3, the analyses have been projected to the end of the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.8 <u>Conclusion for TLAAs</u>

The staff reviewed the information in LRA Section 4, "Time-Limited Aging Analyses." On the basis of its review, the staff concludes that the applicant has provided a sufficient list of TLAAs, as defined in 10 CFR 54.3, and that the applicant has demonstrated that (1) the TLAAs remain valid for the period of extended operation, as required by 10 CFR 54.21(c)(1)(i), (2) the TLAAs have been projected to the end of the period of extended operation, as required by 10 CFR 54.21(c)(1)(ii), or (3) the effects of aging on intended function(s) will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(c)(1)(iii). The staff also reviewed the UFSAR supplement for the TLAAs and finds that the supplement contains descriptions of the TLAAs sufficient to satisfy the requirements of 10 CFR 54.21(d). In addition, the staff concludes, as required by 10 CFR 54.21(c)(2), that no plant-specific, TLAA-based exemptions are in effect.

With regard to these matters, the staff concludes that reasonable assurance exists that the activities authorized by the renewed licenses will continue to be conducted in accordance with the CLB and that any changes made to the CLB, in order to comply with 10 CFR 54.29(a), are in accordance with the Atomic Energy Act of 1954, as amended, and NRC regulations.

SECTION 5

REVIEW BY THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

The NRC staff issued its safety evaluation report with open items related to the renewal of operating licenses for Indian Point Nuclear Generating Unit Nos. 2 and 3 on January 15, 2009. On March 4, 2009, the applicant presented its license renewal application (LRA) and the staff presented its review findings to the ACRS Plant License Renewal Subcommittee. The staff reviewed the applicant's comments on the SER with open items and completed its review of the LRA. The staff's final evaluation is documented in an SER that was issued by letter dated August 11, 2009.

During the 565th meeting of the ACRS, September 10, 2009 through September 12, 2009, the ACRS completed its review of the Indian Point LRA and the NRC staff's SER. The ACRS documented its findings in a report to the Commission dated September 23, 2009. A copy of that letter is provided on the following pages.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, DC 20555 - 0001

September 23, 2009

The Honorable Gregory B. Jaczko
Chairman
U. S. Nuclear Regulatory Commission
Washington, DC 20555-0001

SUBJECT: REPORT ON THE SAFETY ASPECTS OF THE LICENSE RENEWAL APPLICATION FOR THE INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3

Dear Chairman Jaczko:

During the 565th meeting of the Advisory Committee on Reactor Safeguards, September 10-12, 2009, we completed our review of the license renewal application for the Indian Point Nuclear Generating Unit Nos. 2 and 3 (IP2 and IP3), and the final Safety Evaluation Report (SER) prepared by the NRC staff. Our Plant License Renewal Subcommittee also reviewed this matter during its meeting on March 4, 2009. During these reviews, we had the benefit of discussions with representatives of the NRC staff, Riverkeeper Inc., and Entergy Nuclear Operations Inc. (Entergy or the applicant). We also had the benefit of the documents referenced. This report fulfills the requirement of 10 CFR 54.25 that the ACRS review and report on all license renewal applications.

CONCLUSION AND RECOMMENDATION

1. The programs established and committed to by the applicant to manage age-related degradation provide reasonable assurance that IP2 and IP3 can be operated in accordance with their current licensing bases for the period of extended operation without undue risk to the health and safety of the public.

2. The Entergy application for renewal of the operating licenses for IP2 and IP3 should be approved.

BACKGROUND AND DISCUSSION

IP2 and IP3 are Westinghouse 4-loop pressurized water reactors with large, dry ambient pressure containments. They are located approximately 24 miles north of the New York City boundary line. The current licensed power rating of each of the Indian Point units is 3,216 megawatts thermal with a gross electrical output of approximately 1,080 megawatts. Entergy requested renewal of the IP2 and IP3 operating licenses for 20 years beyond the current license terms, which expire on September 28, 2013, for IP2 and December 12, 2015, for IP3.

In the final SER, the staff documented its review of the license renewal application and other information submitted by the applicant or obtained from the staff audits and inspections at the

plant site. The staff reviewed the completeness of the applicant's identification of the structures, systems, and components (SSCs) that are within the scope of license renewal; the integrated plant assessment process; the applicant's identification of the plausible aging mechanisms associated with passive, long-lived components; the adequacy of the applicant's Aging Management Programs (AMPs); and the identification and assessment of time-limited aging analyses (TLAAs) requiring review.

In the license renewal application, Entergy identified the SSCs that fall within the scope of license renewal. For these SSCs, the applicant performed a comprehensive aging management review. Based on this review, the applicant will implement 41 AMPs for license renewal, including 10 new programs, and 31 existing programs of which 16 are enhanced and 9 have exceptions to the Generic Aging Lessons Learned (GALL) Report.

The Entergy application either demonstrates consistency with the GALL Report or documents deviations to the specified approaches in this Report. The Entergy application includes several exceptions to the GALL Report. We reviewed these exceptions and agree with the staff that they are acceptable. The staff conducted five license renewal audits and four inspections at the Indian Point site. The audits verified the appropriateness of the scoping and screening methodology, AMPs, aging management review, and TLAAs. The site inspections verified that the license renewal requirements are appropriately implemented. Based on the audits and inspections, the staff concluded in the final SER that the proposed activities will adequately manage the effects of aging of SSCs identified in the application and that the intended functions of these SSCs will be maintained during the period of extended operation. We agree with this conclusion.

The applicant identified the systems and components requiring TLAAs and reevaluated them for the period of extended operation. The staff concluded that the applicant has provided an adequate list of TLAAs. Further, the staff concluded that the applicant has met the requirements of the License Renewal Rule by demonstrating that the TLAAs will remain valid for the period of extended operation, or that the TLAAs have been projected to the end of the period of extended operation, or that the aging effects will be adequately managed for the period of extended operation.

In 1992, a leak was detected in the IP2 spent fuel pool liner. The leak was determined to be the result of work performed in the spent fuel pool during 1990. Repairs were made to the liner and the structural integrity of the spent fuel pool was evaluated. The evaluation included testing of core bore samples of the concrete to confirm that the structure could perform its intended design function.

Leakage was observed again in 2005. The applicant performed additional testing and inspections of the spent pool liner using visual, robotic camera, and vacuum box testing techniques. This testing identified a pin-hole leak in a weld. The weld flaw was attributed to original construction of the spent fuel pool and was not attributed to any age related degradation mechanism. The leak was repaired and, currently, there is no evidence of continued leakage from the IP2 spent fuel pool.

The applicant has committed to a quarterly sampling program to test for changes in tritium concentrations in groundwater in close proximity to the IP2 spent fuel pool. The applicant has installed over 40 monitoring wells, most of which are multi-level and range up to 300 feet in depth. These wells are configured with level transducers and sample ports for chemical and

radiological sampling. Any significant changes in the groundwater, such as an increase in the tritium level, will be evaluated as an indication of potential leakage from the IP2 spent fuel pool. If leakage is identified in the future, it will be resolved using the applicant's corrective action program.

The staff reviewed Entergy's evaluations, corrective actions, and commitments relative to the IP2 spent fuel pool. Based on the inspections previously conducted and Entergy's commitment to monitor the groundwater samples, the staff concluded that there is reasonable assurance that any future degradation of the IP2 spent fuel pool would be detected. Results from the tritium groundwater monitoring program were used with other information to confirm the source and extent of the leak in the IP2 spent fuel pool. The applicant indicated that the tritium monitoring program will continue to be used to assess the effectiveness of repairs to the IP2 spent fuel pool and to identify any further corrective actions prior to loss of intended functions. Therefore, the staff concluded that the effects of aging will be adequately managed during the period of extended operation. We concur with the staff's conclusions.

The refueling cavity at IP2 has had a history of leakage at the upper elevations of the stainless steel cavity liner when flooded during refueling outages. Once the water gets through flaws in the liner, it travels through gaps in the concrete down to the lower level of the containment where it is collected and pumped to the radioactive waste processing system. Previous corrective actions have reduced, but not eliminated, the leakage. Entergy has performed several inspections and analyses to provide assurance that the leakage is not affecting other structures and that the affected structures remain fully capable of performing their intended design function. To provide additional assurance of the structural integrity, the applicant has committed to perform another inspection that includes taking and analyzing core bore samples of the concrete in affected structures prior to the period of extended operation. Chemical analysis of the water collecting in the lower level of containment will also be performed. During the next three refueling outages, Entergy will perform evaluations and repairs of the liner in an attempt to eliminate the leakage. If the planned repairs do not eliminate the leakage, Entergy will re-inspect the concrete structure and perform chemical analysis of the water prior to the tenth year of the extended period of operation.

The staff evaluated Entergy's inspections and analyses of the structures affected by the leakage. Entergy's mitigation plan and commitments for future inspections were also reviewed. Based on the inspections conducted to date and the actions Entergy is planning to take prior to and during the period of extended operation, the staff concluded that the aging effects on the IP2 refueling cavity concrete will be adequately managed during the period of extended operation. We concur with the staff's conclusion.

In 1973, IP2 experienced a transient in which hot steam and water from a feedwater line leak sprayed onto an uninsulated portion of the containment liner. As a result of the rapid temperature change, the liner buckled and deformed in the affected area. Repairs were made to the liner and the containment was returned to service. Since the 1973 transient, Integrated Leak Rate Tests and inspections have been performed and have confirmed that the containment liner has not experienced any degradation following the repairs. Entergy will perform another inspection of the affected area prior to the period of extended operation.

The staff reviewed Entergy's evaluation and inspection results as well as the monitoring plan and commitments for the containment liner inspections and tests. The staff concluded that the applicant's commitments for future monitoring provide adequate assurance that the

containment liner will remain capable of performing its intended design function during the period of extended operation. We concur with the staff's conclusions.

Entergy predicts that both the IP2 and IP3 reactor vessels will have Charpy Upper-Shelf Energy (USE) values slightly less than 50 ft-lbs at the end of the period of extended operation. IP2 is projected to be at 48.3 ft-lbs and IP3 is projected to be at 49.8 ft-lbs. When a USE value is projected to be less than 50 ft-lbs, 10 CFR Part 50, Appendix G requires that an applicant demonstrate margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code. Appendix K of ASME Code Section XI and ASME Code Case N-512 provide criteria for reactor vessels with Charpy USE values less than 50 ft-lbs. Entergy submitted an equivalent margins analysis demonstrating the applicability of WCAP-13587, Revision 1 to both IP2 and IP3. WCAP-13587, Revision 1 demonstrates that 4-loop plants can meet ASME Code requirements with a Charpy USE of 43 ft-lbs.

The staff reviewed Entergy's equivalent margins analysis and concluded that IP2 and IP3 meet the requirements of 10 CFR Part 50, Appendix G for the projected Charpy USE values. We concur with the staff's conclusion.

Industry experience with leaks in buried piping and tanks has revealed the need for an inspection program. As a result of Indian Point operating experience, such as the recent IP2 condensate return line leak, Entergy amended its buried piping and tanks inspection program to include additional testing of buried components. They have committed to 51 inspections prior to entering the period of extended operation and additional periodic inspections during the period of extended operation. This inspection and monitoring program is consistent with the GALL Report and significantly exceeds the minimum number of inspections required in similar programs at other plants.

The staff reviewed Entergy's amended buried piping and tanks inspection program and concluded it was adequate to manage aging effects. We concur with the staff's conclusion.

We agree with the staff that there are no issues related to the matters described in 10 CFR 54.29(a)(1) and (a)(2) that preclude renewal of the operating licenses for IP2 and IP3. The programs established and committed to by Entergy provide reasonable assurance that IP2 and IP3 can be operated in accordance with their current licensing bases for the period of extended operation without undue risk to the health and safety of the public. The Entergy application for renewal of the operating licenses for IP2 and IP3 should be approved.

Sincerely,

Mario V. Bonaca
Chairman

REFERENCES

1. Memorandum to Edwin M. Hackett, Executive Director, ACRS, transmitting the NRC Final Safety Evaluation Report for Indian Point Nuclear Generating Unit Nos. 2 and 3 License Renewal Application – Safety Evaluation Report, August 18, 2009 (ML092250413 and ML092240268)

2. Letter from F.R. Dacimo (Entergy) to U.S. Nuclear Regulatory Commission, transmitting the Application to Renew the Operating Licenses of Indian Point Nuclear Generating Units No. 2 and 3, April 23, 2007 (ML071210512)

3. U. S. Nuclear Regulatory Commission, "Generic Aging Lessons Learned (GALL) Report," NUREG-1801, Volumes 1 & 2, Revision 1, September 2005 (ML052110005 and ML052110006)

4. Letter from Kimberly Green, Safety Project Manager, NRR, to Entergy Nuclear Operations, Inc., "Audit Reports Regarding the License Renewal Application for the Indian Point Nuclear Generating Unit Nos. 2 and 3, License Renewal Application," January 13, 2009 (ML083540625)

5. Letter from R. J. Conte, Chief, Engineering Branch 1, Region 1, to J. Pollock, Site Vice President, Entergy, "Indian Point Nuclear Generating Units 2 and 3 – NRC License Renewal Inspection Report 05000247/2008006 and 05000286/2008006," August 1, 2008 (ML082140149)

6. Letter from P. Musegaas, Esq. and D. Brancato, Staff Attorney, Riverkeeper, to M. V. Bonaca, Chairman, ACRS, "Comments to the Advisory Committee on Reactor Safeguards on the Indian Point License Renewal Application and Safety Evaluation Report with Open Items," February 27, 2009 (ML092640558)

7. Letter from P. Musegaas, Esq. and D. Brancato, Staff Attorney, Riverkeeper, to O. L. Maynard, ACRS, "Follow-up Comments to the ACRS on the Indian Point License Renewal Application and Safety Evaluation Report with Open Items," dated April 16, 2009 (ML091170625)

8. Letter from D. Brancato, Staff Attorney, Riverkeeper, to M. V. Bonaca, Chairman, ACRS, "September 10-12, 2009 ACRS Meeting to Discuss License Renewal Application and Final Safety Evaluation (SER) Report for the Indian Point Nuclear Generating Units 2 and 3," September 4, 2009 (ML092540360)

9. Letter from M. W. Hodges, NRR, to W. Rasin, Vice President and Director, Nuclear Management and Resources Council, "Staff Safety Assessment of Report WCAP-13587, Revision 1, "Reactor Vessel Upper Shelf Energy Bounding Evaluation for Westinghouse Pressurized Water Reactors," September 1993," April 21, 1994 (ML090580069)

SECTION 6

CONCLUSION

The staff of the U.S. Nuclear Regulatory Commission (NRC) (the staff) reviewed the license renewal application (LRA) for Indian Point Nuclear Generating Unit Nos. 2 and 3, in accordance with NRC regulations and NUREG-1800, Revision 1, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," dated September 2005. Title 10, Section 54.29, of the *Code of Federal Regulations* (10 CFR 54.29) sets the standards for issuance of a renewed license. Pursuant to 10 CFR 54.29(a), the Commission may issue a renewed license if finds that actions have been identified and have been or will be taken, such that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the current licensing basis (CLB).

On the basis of its review of the LRA, the staff determines that the requirements of 10 CFR 54.29(a) have been met.

The staff notes that any requirements of 10 CFR Part 51, Subpart A, will be documented in Supplement 38 to NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding Indian Point Nuclear Generating Unit Nos. 2 and 3."

Appendix A

APPENDIX A

INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS

During the review of the Indian Point Nuclear Generating Unit Nos. 2 and 3 (IP2 and IP3), license renewal application (LRA) by the staff of the U.S. Nuclear Regulatory Commission (NRC) (the staff), Entergy Nuclear Operations, Inc. (Entergy or the applicant) made commitments related to aging management programs (AMPs) to manage the aging effects for certain structures and components during the period of extended operation. The following table lists these commitments along with the applicant's stated implementation schedules and sources for each commitment.

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
1	Enhance the Above Ground Steel Tanks Program for IP2 and IP3 to perform thickness measurements of the bottom surfaces of the condensate storage tanks, city water tank, and fire water tanks once during the first ten years of the period of extended operation. Enhance the Above Ground Steel Tanks Program for IP2 and IP3 to require trending of thickness measurements when material loss is detected.	A.2.1.1 A.3.1.1 B.1.1	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039
2	Enhance the Bolting Integrity Program for IP2 and IP3 to clarify that actual yield strength is used in selecting materials for low susceptibility to SCC and clarify the prohibition on use of lubricants containing MoS_2 for bolting. The Bolting Integrity Program manages loss of preload and loss of material for all external bolting.	A.2.1.2 A.3.1.2 B.1.2 Audit Items 201, 241, 270	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR *Supplement Section/* LRA Section**	**Applicant's *Implementation* Schedule**	**Source**
3	Implement the Buried Piping and Tanks Inspection Program for IP2 and IP3 as described in LRA Section B.1.6. This new program will be implemented consistent with the corresponding described in NUREG-1801, Section XI.M34, Buried Piping and Tanks Inspection. Include in the Buried Piping and Tanks Inspection Program described in LRA Section B.1.6 a risk assessment of in-scope buried piping and tanks that includes consideration of the impacts of buried piping or tank leakage and of conditions affecting the risk for corrosion. Classify pipe segments and tanks as having a high, medium or low impact of leakage based on the safety class, the hazard posed by fluid contained in the piping and the impact of leakage on reliable plant operation. Determine corrosion risk through consideration of piping or tank material, soil resistivity, drainage, the presence of cathodic protection and the type of coating. Establish inspection priority and frequency for periodic inspections of the in-scope piping and tanks based on the results of the risk assessment. Perform inspections using inspection techniques with demonstrated effectiveness.	A.2.1.5 A.3.1.5 B.1.6 Audit Item 173	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 NL-09-106 NL-09-111

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
4	Enhance the Diesel Fuel Monitoring Program to include cleaning and inspection of the IP2 GT-1 gas turbine fuel oil storage tanks, IP2 and IP3 EDG fuel oil day tanks, IP2 SBO/Appendix R diesel generator fuel oil day tank, and IP3 Appendix R fuel oil storage tank and day tank once every ten years. Enhance the Diesel Fuel Monitoring Program to include quarterly sampling and analysis of the IP2 SBO/Appendix R diesel generator fuel oil day tank, IP2 security diesel fuel oil storage tank, IP2 security diesel fuel oil day tank, and IP3 Appendix R fuel oil storage tank. Particulates, water and sediment checks will be performed on the samples. Filterable solids acceptance criterion will be less than or equal to 10mg/l. Water and sediment acceptance criterion will be less than or equal to 0.05%. Enhance the Diesel Fuel Monitoring Program to include thickness measurement of the bottom surface of the following tanks once every ten years. IP2: EDG fuel oil storage tanks, EDG fuel oil day tanks, SBO/Appendix R diesel generator fuel oil day tank, GT-1 gas turbine fuel oil storage tanks, and diesel fire pump fuel oil storage tank; IP3: EDG fuel oil day tanks, Appendix R fuel oil storage tank, and diesel fire pump fuel oil storage tank. Enhance the Diesel Fuel Monitoring Program to change the analysis for water and particulates to a quarterly frequency for the following tanks. IP2: GT-1 gas turbine fuel oil storage tanks and diesel fire pump fuel oil storage tank; IP3: Appendix R fuel oil day tank and diesel fire pump fuel oil storage tank.	A.2.1.8 A.3.1.8 B.1.9 Audit Items 128, 129, 132, 491, 492, 510	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 NL-08-057

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
4 (continued)	Enhance the Diesel Fuel Monitoring Program to specify acceptance criteria for thickness measurements of the fuel oil storage tanks within the scope of the program. Enhance the Diesel Fuel Monitoring Program to direct samples be taken and include direction to remove water when detected. Revise applicable procedures to direct sampling of the onsite portable fuel oil contents prior to transferring the contents prior to transferring the contents to storage. Enhance the Diesel Fuel Monitoring Program to direct the addition of chemicals including biocide when the presence of biological activity is confirmed.			
5	Enhance the External Surfaces Monitoring Program for IP2 and IP3 to include periodic inspections of systems in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(1) and (a)(3). Inspections shall include areas surrounding the subject systems to identify hazards to those systems. Inspections of nearby systems that could impact the subject systems will include SSCs that are in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(2).	A.2.1.10 A.3.1.10 B.1.11	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
6	Enhance the Fatigue Monitoring Program for IP2 to monitor steady state cycles and feedwater cycles or perform an evaluation to determine monitoring is not required. Review the number of allowed events and resolve discrepancies between reference documents and monitoring procedures. Enhance the Fatigue Monitoring Program for IP3 to include all the transients identified. Assure all fatigue analysis transients are included with the lowest limiting numbers. Update the number of design transients accumulated to date.	A.2.1.11 A.3.1.11 B.1.12 Audit Item 164	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ *LRA Section***	**Applicant's Implementation *Schedule***	**Source**
7	Enhance the Fire Protection Program to inspect external surfaces of the IP3 RCP oil collection systems for loss of material each refueling cycle. Enhance the Fire Protection Program to explicitly state that the IP2 and IP3 diesel fire pump engine sub-systems (including the fuel supply line) shall be observed while the pump is running. Acceptance criteria will be revised to verify that the diesel engine does not exhibit signs of degradation while running; such as fuel oil, lube oil, coolant, or exhaust gas leakage. Enhance the Fire Protection Program to specify that the IP2 and IP3 diesel fire pump engine carbon steel exhaust components are inspected for evidence of corrosion and cracking at least once each operating cycle. Enhance the Fire Protection Program for IP3 to visually inspect the cable spreading room, 480V switchgear room, and EDG room CO_2 fire suppression system for signs of degradation, such as corrosion and mechanical damage at least once every six months.	A.2.1.12 A.3.1.12 B.1.13	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
8	Enhance the Fire Water Program to include inspection of IP2 and IP3 hose reels for evidence of corrosion. Acceptance criteria will be revised to verify no unacceptable signs of degradation. Enhance the Fire Water Program to inspect a sample of IP2 and IP3 sprinkler heads required for 10 CFR 50.48 using guidance of NFPA 25 (2002 edition), Section 5.3.1.1.1 before the end of the 50-year sprinkler head service life and at 10-year intervals thereafter during the extended period of operation to ensure that signs of degradation, such as corrosion, are detected in a timely manner. Enhance the Fire Water Program to perform wall thickness evaluations of IP2 and IP3 fire protection piping on system components using non-intrusive techniques (e.g., volumetric testing) to identify evidence of loss of material due to corrosion. These inspections will be performed before the end of the current operating term and at intervals thereafter during the period of extended operation. Results of the initial evaluations will be used to determine the appropriate inspection interval to ensure aging effects are identified prior to loss of intended function. Enhance the Fire Water Program to inspect the internal surface of the IP3 foam based fire suppression tanks. Acceptance criteria will be enhanced to verify no significant corrosion.	A.2.1.13 A.3.1.13 B.1.14 Audit Items 105, 106	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 NL-08-014

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
9	Enhance the Flux Thimble Tube Inspection Program for IP2 and IP3 to implement comparisons to wear rates identified in WCAP-12866. Include provisions to compare data to the previous performances and perform evaluations regarding change to test frequency and scope. Enhance the Flux Thimble Tube Inspection Program for IP2 and IP3 to specify the acceptance criteria as outlined in WCAP-12866 or other plant-specific values based on evaluation of previous test results. Enhance the Flux Thimble Tube Inspection Program for IP2 and IP3 to direct evaluation and performance of corrective actions based on tubes that exceed or are projected to exceed the acceptance criteria. Also stipulate that flux thimble tubes that cannot be inspected over the tube length and cannot be shown by analysis to be satisfactory for continued service, must be removed from service to ensure the integrity of the reactor coolant system pressure boundary.	A.2.1.15 A.3.1.15 B.1.16	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS

Item Number	Commitment	UFSAR Supplement Section/ LRA Section	Applicant's Implementation Schedule	Source
10	Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to include the following heat exchangers in the scope of the program. • Safety injection pump lube oil heat exchangers • RHR heat exchangers • RHR pump seal coolers • Non-regenerative heat exchangers • Charging pump seal water heat exchangers • Charging pump fluid drive coolers • Charging pump crankcase oil coolers • Spent fuel pit heat exchangers • Secondary system steam generator sample coolers • Waste gas compressor heat exchangers • SBO/Appendix R diesel jacket water heat exchanger (IP2 only) Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to perform visual inspection on heat exchangers where non-destructive examination, such as eddy current inspection, is not possible due to heat exchanger design limitations. Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to include consideration of material-environment combinations when determining sample population of heat exchangers.	A.2.1.16 A.3.1.16 B.1.17 Audit Item 52	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
10 (continued)	Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to establish minimum tube wall thickness for the new heat exchangers identified in the scope of the program. Establish acceptance criteria for heat exchangers visually inspected to include no unacceptable signs of degradation.			
11	Deleted	Not applicable	Not applicable	NL-09-056
12	Enhance the Masonry Wall Program for IP2 and IP3 to specify that the IP1 intake structure is included in the program.	A.2.1.18 A.3.1.18 B.1.19	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
13	Enhance the Metal-Enclosed Bus Inspection Program to add IP2 480V bus associated with substation A to the scope of the bus inspected. Enhance the Metal-Enclosed Bus Inspection Program for IP2 and IP3 to visually inspect the external surface of metal-enclosed bus enclosure assemblies for loss of material at least once every 10 years. The first inspection will occur prior to the period of extended operation and the acceptance criterion will be no significant loss of material. Enhance the Metal-Enclosed Bus Inspection Program to add acceptance criteria for MEB internal visual inspections to include the absence of indications of dust accumulation on the bus bar, on the insulators, and in the duct, in addition to the absence of indications of moisture intrusion into the duct. Enhance the Metal-Enclosed Bus Inspection Program for IP2 and IP3 to inspect bolted connections at least once every five years if performed visually or at least once every ten years using quantitative measurements. The first inspection will occur prior to the period of extended operation. The plant will process a change to applicable site procedure to remove the reference to "re-torquing" connections for phase bus maintenance and bolted connection maintenance.	A.2.1.19 A.3.1.19 B.1.20 Audit Item 124, 133, 519	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 NL-08-057

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
14	Implement the Non-EQ Bolted Cable Connections Program for IP2 and IP3 as described in LRA Section B.1.22.	A.2.1.21 A.3.1.21 B.1.22	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039
15	Implement the Non-EQ Inaccessible Medium-Voltage Cable Program for IP2 and IP3 as described in LRA Section B.1.23. This new program will be implemented consistent with the corresponding described in NUREG-1801, Section XI.E3, Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.	A.2.1.22 A.3.1.22 B.1.23 Audit Item 173	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153
16	Implement the Non-EQ Instrumentation Circuits Test Review Program for IP2 and IP3 as described in LRA Section B.1.24. This new program will be implemented consistent with the corresponding described in NUREG-1801, Section XI.E2, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits.	A.2.1.23 A.3.1.23 B.1.24 Audit Item 173	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153
17	Implement the Non-EQ Insulated Cables and Connections Program for IP2 and IP3 as described in LRA Section B.1.25. This new program will be implemented consistent with the corresponding described in NUREG-1801, Section XI.E1, Electrical Cables and Connections Not Subject to 10 CFR 50.39 Environmental Qualification Requirements.	A.2.1.24 A.3.1.24 B.1.25 Audit Item 173	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
18	Enhance the Oil Analysis Program for IP2 to sample and analyze lubricating oil used in the SBO/Appendix R diesel generator consistent with the oil analysis for other site diesel generators. Enhance the Oil Analysis Program for IP2 and IP3 to sample and analyze generator seal oil and turbine hydraulic control oil. Enhance the Oil Analysis Program for IP2 and IP3 to formalize preliminary oil screening for water and particulates and laboratory analyses including defined acceptance criteria for all components included in the scope of this program. The program will specify corrective actions in the event acceptance criteria are not met. Enhance the Oil Analysis Program for IP2 and IP3 to formalize trending of preliminary oil screening results as well as data provided from independent laboratories.	A.2.1.25 A.3.1.25 B.1.26	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039
19	Implement the One-Time Inspection Program for IP2 and IP3 as described in LRA Section B.1.27. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M32, One-Time Inspection.	A.2.1.26 A.3.1.26 B.1.27 Audit Item 173	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
20	Implement the One-Time Inspection – Small Bore Piping Program for IP2 and IP3 as described in LRA Section B.1.28. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M35, One-Time Inspection of ASME Code Class I Small-Bore Piping.	A.2.1.27 A.3.1.27 B.1.28 Audit Item 173	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153
21	Enhance the Periodic Surveillance and Preventive Maintenance Program for IP2 and IP3 as necessary to assure that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of operation.	A.2.1.28 A.3.1.28 B.1.29	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039
22	Enhance the Reactor Vessel Surveillance Program for IP2 and IP3 revising the specimen capsule withdrawal schedules to draw and test a standby capsule to cover the peak reactor vessel fluence expected through the end of the period of extended operation. Enhance the Reactor Vessel Surveillance Program for IP2 and IP3 to require that tested and untested specimens from all capsules pulled from the reactor vessel are maintained in storage.	A.2.1.31 A.3.1.31 B.1.32	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
23	Implement the Selective Leaching Program for IP2 and IP3 as described in LRA Section B.1.33. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M33, Selective Leaching of Materials.	A.2.1.32 A.3.1.32 B.1.33 Audit Item 173	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153
24	Enhance the Steam Generator Integrity Program for IP2 and IP3 to require that the results of the condition monitoring assessment are compared to the operational assessment performed for the prior operating cycle with differences evaluated.	A.2.1.34 A.3.1.34 B.1.35	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
25	Enhance the Structures Monitoring Program to explicitly specify that the following structures are included in the program. • Appendix R diesel generator foundation (IP3) • Appendix R diesel generator fuel oil tank vault (IP3) • Appendix R diesel generator switchgear and enclosure (IP3) • city water storage tank foundation • condensate storage tanks foundation (IP3) • containment access facility and annex (IP3) • discharge canal (IP2/3) • emergency lighting poles and foundations (IP2/3) • fire pumphouse (IP2) • fire protection pumphouse (IP3) • fire water storage tank foundations (IP2/3) • gas turbine 1 fuel storage tank foundation • maintenance and outage building-elevated passageway (IP2) • new station security building (IP2) • nuclear service building (IP1) • primary water storage tank foundation (IP3) • refueling water storage tank foundation (IP3) • security access and office building (IP3) • service water pipe chase (IP2/3) • service water valve pit (IP3) • superheater stack • transformer/switchyard support structures (IP2) • waste holdup tank pits (IP2/3)	A.2.1.35 A.3.1.35 B.1.36 Audit Items 86, 87, 88, 417, 358, 360	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153 NL-08-057 NL-08-127

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
25 (continued)	Enhance the Structures Monitoring Program for IP2 and IP3 to clarify that in addition to structural steel and concrete, the following commodities (including their anchorages) are inspected for each structure as applicable. • cable trays and supports • concrete portion of reactor vessel supports • conduits and supports • cranes, rails and girders • equipment pads and foundations • fire proofing (pyrocrete) • HVAC duct supports • jib cranes • manholes and duct banks • manways, hatches and hatch covers • monorails • new fuel storage racks • sumps, sump screens, strainers and flow barriers Enhance the Structures Monitoring Program for IP2 and IP3 to inspect inaccessible concrete areas that are exposed by excavation for any reason. IP2 and IP3 will also inspect inaccessible concrete areas in environments where observed conditions in accessible areas exposed to the same environment indicate that significant concrete degradation is occurring.			

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
25 (*continued*)	Enhance the Structures Monitoring Program for IP2 and IP3 to perform inspections of elastomers (seals, gaskets, seismic joint filler, and roof elastomers) to identify cracking and change in material properties and for inspection of aluminum vents and louvers to identify loss of material. Enhance the Structures Monitoring Program for IP2 and IP3 to perform an engineering evaluation of groundwater samples to assess aggressiveness of groundwater to concrete on a periodic basis (at least once every five years). IPEC will obtain samples from at least 5 wells that are representative of the ground water surrounding below-grade site structures and perform an engineering evaluation of the results from those samples for sulfates, pH and chlorides. Additionally, to assess potential indications of spent fuel pool leakage, IPEC will sample for tritium in groundwater wells in close proximity to the IP2 spent fuel pool at least once every 3 months. Enhance the Structures Monitoring Program for IP2 and IP3 to perform inspection of normally submerged concrete portions of the intake structures at least once every 5 years. Inspect the baffling/grating partition and support platform of the IP3 intake structure at least once every 5 years. Enhance the Structures Monitoring Program for IP2 and IP3 to perform inspection of the degraded areas of the water control structure once per 3 years rather than the normal frequency of once per 5 years during the PEO.			

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS

Item Number	Commitment	UFSAR Supplement Section/ LRA Section	Applicant's Implementation Schedule	Source
26	Implement the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program for IP2 and IP3 as described in LRA Section B.1.37. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M12, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program.	A.2.1.36 A.3.1.36 B.1.37 Audit Item 173	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153
27	Implement the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program for IP2 and IP3 as described in LRA Section B.1.38. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M13, Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel (CASS) Program.	A.2.1.37 A.3.1.37 B.1.38 Audit Item 173	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-07-153
28	Enhance the Water Chemistry Control – Closed Cooling Water Program to maintain water chemistry of the IP2 SBO/Appendix R diesel generator cooling system per EPRI guidelines. Enhance the Water Chemistry Control – Closed Cooling Water Program to maintain the IP2 and IP3 security generator and fire protection diesel cooling water pH and glycol within limits specified by EPRI guidelines.	A.2.1.39 A.3.1.39 B.1.40 Audit Item 509	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039 NL-08-057
29	Enhance the Water Chemistry Control – Primary and Secondary Program for IP2 to test sulfates monthly in the RWST with a limit of <150 ppb.	A.2.1.40 B.1.41	IP2: September 28, 2013	NL-07-039

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
30	For aging management of the reactor vessel internals, IPEC will (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval.	A.2.1.41 A.3.1.41	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039
31	Additional P-T curves will be submitted as required per 10 CFR 50, Appendix G prior to the period of extended operation as part of the Reactor Vessel Surveillance Program.	A.2.2.1.2 A.3.2.1.2 4.2.3	IP2: September 28, 2013 IP3: December 12, 2015	NL-07-039
32	As required by 10 CFR 50.61(b)4), IP3 will submit a plant-specific safety analysis for plate B2803-3 to the NRC three years prior to reaching the RT_{PTS} screening criterion. Alternatively, the site may choose to implement the revised PTS rule when approved.	A.3.2.1.4 4.2.5	IP3: December 12, 2015	NL-07-039 NL-08-127

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
33	At least 2 years prior to entering the period of extended operation, for the locations identified in LRA Table 4.3-13 (IP2) and LRA Table 4.3-14 (IP3), under the Fatigue Monitoring Program, IP2 and IP3 will implement one or more of the following: (1) Consistent with the Fatigue Monitoring Program, Detection of Aging Effects, update the fatigue usage calculations using refined fatigue analyses to determine valid CUFs less than 1.0 when accounting for the effects of reactor water environment. This includes applying the appropriate Fen factors to valid CUFs determined in accordance with one of the following: 1. For locations in LRA Table 4.3-13 (IP2) and LRA Table 4.3-14 (IP3), with existing fatigue analysis valid for the period of extended operation, use the existing CUF. 2. Additional plant-specific locations with a valid CUF may be evaluated. In particular, the pressurizer lower shell will be reviewed to ensure the surge nozzle remains the limiting component. 3. Representative CUF values from other plants, adjusted to or enveloping the IPEC plant specific external loads may be used if demonstrated applicable to IPEC. 4. An analysis using an NRC-approved version of the ASME code or NRC-approved alternative (e.g., NRC-approved code case) may be performed to determine a valid CUF.	A.2.2.2.3 A.3.2.2.3 4.3.3 Audit Item 146	IP2: September 28, 2011 IP3: December 12, 2013	NL-07-039 NL-07-153 NL-08-021

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APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
33 (continued)	(2) Consistent with the Fatigue Monitoring Program, Corrective Actions, repair or replace the affected locations before exceeding a CUF of 1.0.			
34	IP2 SBO/Appendix R diesel generator will be installed and operational by April 30, 2008. This committed change to the facility meets the requirements of 10 CFR 50.59(c)(1) and, therefore, a license amendment pursuant to 10 CFR 50.90 is not required.	2.1.1.3.5	April 30, 2008 Complete	NL-07-078 NL-08-074
35	Perform a one-time inspection of representative sample area of IP2 containment liner affected by the 1973 event behind the insulation, prior to entering the period of extended operation, to assure liner degradation is not occurring in this area. Perform a one-time inspection of representative sample area of the IP3 containment steel liner at the juncture with the concrete floor slab, prior to entering the period of extended operation, to assure liner degradation is not occurring in this area. Any degradation will be evaluated for updating of the containment liner analyses as needed.	Audit Item 27	IP2: September 28, 2013 IP3: December 12, 2015	NL-08-127 NL-09-018

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
36	Perform a one-time inspection and evaluation of a sample of potentially affected IP2 refueling cavity concrete prior to the period of extended operation. The sample will be obtained by core boring the refueling cavity wall in an area that is susceptible to exposure to borated water leakage. The inspection will include an assessment of embedded reinforcing steel. Additional core bore samples will be taken, if the leakage is not stopped, prior to the end of the first ten years of the period of extended operation. A sample of leakage fluid will be analyzed to determine the composition of the fluid. If additional core samples are taken prior to the end of the first ten years of the period of extended operation, a sample of leakage fluid will be analyzed.	Audit Item 359	IP2: September 28, 2013	NL-08-127 NL-09-056 NL-09-079
37	Enhance the Containment Inservice Inspection (CII-IWL) Program to include inspections of the containment using enhanced characterization of degradation (i.e., quantifying the dimensions of noted indications through the use of optical aids) during the period of extended operation. The enhancement includes obtaining critical dimensional data of degradation where possible through direct measurement or the use of scaling technologies for photographs, and the use of consistent vantage points for visual inspections.	Audit Item 361	IP2: September 28, 2013 IP3: December 12, 2015	NL-08-127

APPENDIX A: INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3 LICENSE RENEWAL COMMITMENTS				
Item Number	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Applicant's Implementation Schedule**	**Source**
38	For Reactor Vessel Fluence, should future core loading patterns invalidate the basis for the projected values of RT_{PTS} or C_VUSE, updated calculations will be provided to the NRC.	4.2.1	IP2: September 28, 2013 IP3: December 12, 2015	NL-08-143
39	Deleted		Not applicable	NL-09-079
40	Evaluate plant specific and appropriate industry operating experience and incorporate lessons learned in establishing appropriate monitoring and inspection frequencies to assess aging effects for the new aging management programs. Documentation of the operating experience evaluated for each new program will be available on site for NRC review prior to the period of extended operation.	B.1.6 B.1.22 B.1.23 B.1.24 B.1.25 B.1.27 B.1.28 B.1.33 B.1.37 B.1.38	IP2: September 28, 2013 IP3: December 12, 2015	NL-09-106

Appendix B

APPENDIX B

CHRONOLOGY

This appendix lists chronologically the licensing correspondence between the staff of the U.S. Nuclear Regulatory Commission (NRC) (the staff) and Entergy Nuclear Operations, Inc. (Entergy or the applicant). This appendix also lists other correspondence concerning the staff's review of the Indian Point Nuclear Generating Unit Nos. 2 and 3 license renewal application (LRA) (Docket Nos. 50-247 and 50-286).

APPENDIX B: CHRONOLOGY	
Date	**Subject**
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application (ADAMS Accession No. ML071210512)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3 - License Renewal Application Boundary Drawings (ADAMS Accession No. ML071210112)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Cover. (ADAMS Accession No. ML071210516)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Page i, Preface through Chapter 4.0, Page 4.7-4. (ADAMS Accession No. ML071210517)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Appendix A, Updated Final Safety Analysis Report Supplement (ADAMS Accession No. ML071210520)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Appendix B, Aging Management Programs and Activities (ADAMS Accession No. ML071210523)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Appendix C (ADAMS Accession No. ML071210524)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Appendix D, Technical Specification Changes (ADAMS Accession No. ML071210527)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Appendix E, Applicant's Environment Report (ADAMS Accession No. ML071210530)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Attachment A, Threatened and Endangered Species Correspondence (ADAMS Accession No. ML071210553)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Attachment B, Historical and Archeological Properties Correspondence (ADAMS Accession No. ML071210558)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Attachment C, Clean Water Act Documentation (ADAMS Accession No. ML071210560)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Attachment D, Coastal Management Program Consistency Determination (ADAMS Accession No. ML071210562)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Appendix E List of Section 2 Figures (ADAMS Accession No. ML071210565)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Appendix E Figure 2-1 through Figure 2-6 (ADAMS Accession No. ML071210567)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Appendix E Figure 2-7 through Figure 2-12 (ADAMS Accession No. ML071210569)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Appendix E Figure 2-13 through Figure 2-17 (ADAMS Accession No. ML071210570)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Appendix E Figure 2-18 through Figure 2-23 (ADAMS Accession No. ML071210572)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application. Appendix E Figure 2-24 through Figure 2-29 (ADAMS Accession No. ML071210574)
04/23/2007	Indian Point Nuclear Generating Units 2 and 3, License Renewal Application Environmental Report References (ADAMS Accession No. ML071210108)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
05/03/2007	Indian Point Nuclear Generating Units 2 and 3 - Supplement to License Renewal Application (ADAMS Accession No. ML071280700)
05/07/2007	Federal Register Notice, Receipt and Availability of the License Renewal Application for the Indian Point Nuclear Generating Unit Nos. 2 and 3 (ADAMS Accession No. ML071080133)
05/31/2007	Meeting Notice, Forthcoming Meeting to Discuss the License Renewal Review Process for Indian Point Nuclear Generating Unit Nos. 2 and 3 License Renewal Application (LRA) (ADAMS Accession No. ML071450442)
06/13/2007	Press Release-I-07-034 - NRC to Discuss Process for Review of License Renewal Application for Indian Point (ADAMS Accession No. ML071640225)
06/18/2007	Letter from NRC to Entergy Nuclear Operations, Inc, Review Status of the License Renewal Application (LRA) for the Indian Point Nuclear Generating Unit Nos. 2 and 3 (ADAMS Accession No. ML071630049)
06/21/2007	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Unit 2, Station Blackout (SBO) / Appendix R Diesel Generator Commitment, Response to NRC Review Status of License Renewal Application (ADAMS Accession No. ML071800318)
07/10/2007	Conference Call Summary Regarding Status of Acceptance Review for the Indian Point Nuclear Generating Unit Nos. 2 and 3 License Renewal Application (ADAMS Accession No. ML071690181)
07/25/2007	Federal Register Notice, Determination of Acceptability and Sufficiency for Docketing, Proposed Review Schedule, and Opportunity for a Hearing Regarding the Application from ENO, Inc. For Renewal of the Operating License for the Indian Point Nuclear Generating Unit Nos. 2 and 3 (ADAMS Accession No. ML071900365)
07/25/2007	Press Release-07-091 - NRC Announces Opportunity to Request Hearing on Application to Renew Operating License for Indian Point Nuclear Power Plant (ADAMS Accession No. ML072060515)
08/06/2007	Federal Register Notice, Notice of Intent to Prepare an Environmental Impact Statement and Conduct Scoping Process for License Renewal for the Indian Point Nuclear Generating Units 2 and 3 (TAC MD5411 and MD 5412) (ADAMS Accession No. ML071840939)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
08/20/2007	Letter from NRC to Entergy Nuclear Operations, Inc., Summary of Public Meetings Related to the License Renewal Process for the Indian Point Nuclear Generating Unit Nos. 2 and 3, License Renewal Application (ADAMS Accession No. ML072180136)
09/11/2007	Press Release-I-07-046 - NRC to Solicit Public Comments on Sept. 19 as Part of Indian Point License Renewal Application Review (ADAMS Accession No. ML072540791)
09/27/2007	Audit and Review Plan for Plant Aging Management Review and Programs for the Indian Point Units 2 and 3 (ADAMS Accession No. ML072290180)
10/11/2007	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Units 2 and 3 - Supplement to License Renewal Application (LRA) (ADAMS Accession No. ML072910276)
10/16/2007	09/21/2007 Summary of Telephone Conference Call Held Between the U.S. Nuclear Regulatory Commission and Entergy Nuclear Operations, Inc., Concerning Draft Requests for Additional Information (ADAMS Accession No. ML072770605)
10/16/2007	10/02/2007 Summary of Telephone Conference Call Held Between the U.S. Nuclear Regulatory Commission and Entergy Nuclear Operations, Inc., Concerning Requests for Additional Information (ADAMS Accession No. ML072780439)
10/24/2007	Letter from NRC to Entergy Nuclear Operations, Inc, Requests for Additional Information for the Review of the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application (ADAMS Accession No. ML072920027)
10/29/2007	Letter from NRC to Entergy Nuclear Operations, Inc., Request for Additional Information for the Review of the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application (ADAMS Accession No. ML072920229)
11/09/2007	Letter from NRC to Entergy Nuclear Operations, Inc., Request for Additional Information for the Review of the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application (ADAMS Accession No. ML073060401)
11/16/2007	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Units 2 and 3 - Reply to Request for Additional Information Regarding License Renewal Application (ADAMS Accession No. ML073320225)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
11/19/2007	10/11/2007 Summary of Telephone Conference Call Between the NRC and Entergy Concerning D-RAIs Pertaining to the Indian Point LRA (ADAMS Accession No. ML073170649)
11/21/2007	11/01/2007 Summary of Telephone Conference Call Between the NRC and Entergy Concerning Draft Requests for Additional Information Pertaining to the Indian Point Nuclear Generating Units 2 and 3, LRA (ADAMS Accession No. ML073110364)
11/28/2007	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Units 2 and 3 - Reply to Request for Additional Information Regarding License Renewal Application (ADAMS Accession No. ML073460037)
12/06/2007	Letter from Entergy Nuclear Operations, Inc., to NRC, Reply to Request for Additional Information, Regarding License Renewal Application (ADAMS Accession No. ML073470241)
12/07/2007	11/15/2007 Summary of Telephone Conference Call Between the NRC and Entergy Nuclear Operations, Inc., Concerning Draft Requests for Additional Information Pertaining to the Indian Point Nuclear Generating Units 2 and 3 (ADAMS Accession No. ML073250152)
12/07/2007	11/13/2007 Summary of Telephone Conference Call Between NRC and Entergy Nuclear Operations, Inc., Concerning Draft Requests for Additional Information Pertaining to Indian Point (ADAMS Accession No. ML073190360)
12/07/2007	Letter from NRC to Entergy Nuclear Operations, Inc., Request for Additional Information for the Review of the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application (ADAMS Accession No. ML073190401)
12/07/2007	Letter from NRC to Entergy Nuclear Operations, Inc., Request for Additional Information for the Review of the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application (ADAMS Accession No. ML073250226)
12/18/2007	12/04/2007 Summary of Telephone Conference Call Between the NRC and Entergy Nuclear Operations, Inc., Concerning Draft RAI Pertaining to the Indian Point Nuclear Generating Units 2 and 3, LRA-Reactor Coolant Pump Flywheel and Leak Before Break Analyses (ADAMS Accession No. ML073460905)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
12/18/2007	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Units 2 and 3, Amendment 1 to License Renewal Application (ADAMS Accession No. ML073650195)
12/18/2007	12/03/2007 Summary of Telephone Conference Call Between NRC and Entergy Nuclear Operations, Inc., Concerning Requests for Additional Information Pertaining to Indian Point Nuclear Generating Units 2 and 3 (ADAMS Accession No. ML073450399)
12/20/2007	12/04/2007 Summary of Telephone Conference Call Between the NRC and Entergy Nuclear Operations, Inc., Concerning RAIs Pertaining to the Indian Point Nuclear Generating Units 2 and 3, LRA - Reactor Vessel Surveillance and Neutron Embrittlement (ADAMS Accession No. ML073450327)
12/20/2007	12/04/2007 Summary of Telephone Conference Call Between the NRC and Entergy Nuclear Operations, Inc., Concerning RAIs Pertaining to Indian Point Nuclear Generating Units 2 and 3, LRA - Station Blackout Recovery (ADAMS Accession No. ML073450261)
12/21/2007	Letter from NRC to Entergy Nuclear Operations, Inc., Requests for Additional Information for the Review of Indian Point Nuclear Generating Units 2 and 3, LRA - Reactor Coolant Pump Flywheel and Leak Break Analysis (ADAMS Accession No. ML073460141)
01/04/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Units 2 and 3 - Reply to Request for Additional Information, Regarding License Renewal Application (Steam Generator Tube Integrity and Chemistry) (ADAMS Accession No. ML080160123)
01/04/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Units 2 and 3 - Reply to Request for Additional Information Regarding License Renewal Application-(Balance of Plant Systems) (ADAMS Accession No. ML080160284)
01/14/2008	Letter from NRC to Entergy Nuclear Operations, Inc., Request for Additional Information for the Review of the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application - Scoping and Screening Methodology (ADAMS Accession No. ML080100645)
01/17/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, Reply to Request for Additional Information Regarding License Renewal Application - (Reactor Coolant Pump Flywheel and Leak Before Break Analyses) (ADAMS Accession No. ML080250026)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
01/17/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Units 2 and 3 - Clarifications to Reactor Vessel Surveillance Program and Neutron Embrittlement Time-Limited Aging Analyses and Audit Item #105; and Revision to License Renewal Regulatory Commitment List (ADAMS Accession No. ML080250027)
01/22/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Units 2 and 3, License Renewal Application Amendment 2 (ADAMS Accession No. ML080290659)
01/22/2008	01/09/2008 Summary of Telephone Conference Call Between the NRC and Entergy Nuclear Operations, Inc., Concerning Draft RAI Pertaining to Indian Point Nuclear Generating Units 2 and 3, License Renewal Application - Reactor Coolant System (ADAMS Accession No. ML080180420)
01/24/2008	01/09/2008 Summary of Telephone Conference Call Between the NRC and Entergy Nuclear Operations, Inc., Concerning Draft Request for Additional Information Pertaining to the Indian Point Nuclear Generating Unit (ADAMS Accession No. ML080220466)
01/24/2008	Letter from NRC to Entergy Nuclear Operations, Inc., Revision of Schedule for the Conduct of Review of the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application (ADAMS Accession No. ML080230115)
01/28/2008	01/22/2008 Summary of Telephone Conference Call Between the NRC and Entergy Nuclear Operations, Inc., Concerning the Indian Point Nuclear Generating Units 2 and 3, LRA - Metal Fatigue (ADAMS Accession No. ML080230370)
01/28/2008	Letter from NRC to Entergy Nuclear Operations, Inc., Request for Additional Information for the Review of the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application - Reactor Coolant System and Structures (ADAMS Accession No. ML080220099)
02/13/2008	02/07/2008 Summary of Telephone Conference Call Between NRC and Entergy Nuclear Operations, Inc., Concerning Responses to Request for Additional Information Pertaining to Indian Point Nuclear Generating Units 2 and 3, License Renewal Application - Containment Coatings (ADAMS Accession No. ML080420430)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
02/13/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Units 2 and 3, Reply to Request for Additional Information Regarding License Renewal Application - Scoping and Screening Methodology (ADAMS Accession No. ML080510579)
02/13/2008	Letter from NRC to Entergy Nuclear Operations, Inc., Request for Additional Information for the Review of the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application - Balance of Plant, Fire Protection and Nickel Alloy (ADAMS Accession No. ML080380429)
02/27/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Units 2 and 3, Reply to Request for Additional Information Regarding License Renewal Application - Reactor Coolant System and Structures (ADAMS Accession No. ML080640843)
03/10/2008	02/08/2008 Summary of Telephone Conference Call Between the NRC and Entergy Nuclear Operations, Inc., Concerning Response to Audit Item Related to the Indian Point Nuclear Generation Unit Nos. 2 and 3 (ADAMS Accession No. ML080420629)
03/12/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Units 2 and 3, Reply to Request for Additional Information Regarding License Renewal Application - Balance of Plant, Fire Protection, and Nickel Alloy (ADAMS Accession No. ML080780438)
03/24/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Units 2 and 3 - Amendment 3 to License Renewal Application (ADAMS Accession No. ML081070255)
04/02/2008	03/07/2008 - Summary of Telephone Conference Call Between NRC and Entergy Nuclear Operations, Inc., Concerning Responses to Request for Additional Information Related to the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application (ADAMS Accession No. ML080840568)
04/03/2008	03/18/2008 Summary of Telephone Conference Call Between NRC and Entergy Nuclear Operations, Inc., Concerning Response to Audit Item Related to the Indian Point Nuclear Generating Unit Nos. 2 and 3, License Renewal Application (ADAMS Accession No. ML080850050)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
04/09/2008	02/12/2008 Summary of Telephone Conference Call Between NRC and Entergy Nuclear Operations, Inc., Concerning Request for Additional Information Related to the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application Leak Before Break Analyses (ADAMS Accession No. ML080800437)
04/18/2008	Letter from NRC to Entergy Nuclear Operations, Inc., Request for Additional Information, Review of License Renewal Application - Time-Limited Aging Analyses, Bolted Connections, and Boraflex (ADAMS Accession No. ML080870374)
04/23/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Units 2 and 3 - Reply to Request for Additional Information Regarding Site Audit Review of License Renewal Application (ADAMS Accession No. ML081230243)
04/23/2008	Letter from NRC to Entergy Nuclear Operations, Inc., Revision of Schedule for the Review of the Indian Point Nuclear Generating Units 2 and 3 License Renewal Application (ADAMS Accession No. ML081000441)
04/29/2008	Letter from NRC to Entergy Nuclear Operations, Inc., Request for Additional Information for the Review of the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application - Metal Enclosed Buses and Fire Protection (ADAMS Accession No. ML081150435)
04/30/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Units 2 and 3, Amendment 4 to License Renewal Application (ADAMS Accession No. ML081280491)
05/07/2008	Letter from NRC to Entergy Nuclear Operations, Inc., Request for Additional Information for Review of Indian Point Nuclear Generating Units 2 and 3, License Renewal Application - Operating Experience (ADAMS Accession No. ML081230082)
05/08/2008	04/14/2008 Summary of Telephone Conference Call Between NRC and Entergy Nuclear Operations, Inc., Concerning Response to Audit Items Related to Indian Point Nuclear Generating Units 2 and 3, License Renewal Application- Submerged Cables (ADAMS Accession No. ML081280586)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
05/08/2008	04/3/2008 Summary of Telephone Conference Call Between NRC and Entergy Nuclear Operations, Inc., Concerning Responses to Request for Additional Information Related to the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application - Metal Fatigue (ADAMS Accession No. ML081190059)
05/08/2008	Summary of Telephone Conference Calls Held on 4/16 and 4/28/08 Between NRC and Entergy Concerning Responses to RAI Related to Indian Point Nuclear Generating Units 2 and 3 (ADAMS Accession No. ML081160391)
05/12/2008	Letter from NRC to Entergy Nuclear Operations, Inc., Request for Additional Information for Review of Indian Point Nuclear Generating Units 2 and 3, License Renewal Application - Structures (ADAMS Accession No. ML081230347)
05/12/2008	04/28/2008 Summary of Telephone Conference Call Between NRC and Entergy Nuclear Operations, Inc., Concerning Responses to Request for Additional Information Related to the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application – Operating Experience (ADAMS Accession No. ML081260345)
05/16/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Units 2 and 3, Reply to Request for Additional Information Regarding License Renewal Application Time-Limited Aging Analyses and Boraflex (ADAMS Accession No. ML081490317)
05/23/2008	05/07/2008 Summary of Telephone Conference Between NRC and Entergy Nuclear Operations, Inc., Related to the Indian Point Nuclear Generating Unit Nos. 2 and 3, License Renewal Application - Status of Open Items (ADAMS Accession No. ML081400821)
05/28/2008	Letter from NRC to Entergy Nuclear Operations, Inc., Request For Additional Information for the Review of the Indian Point Nuclear Generating Units 2 And 3, License Renewal Application - Inaccessible of Underground Cables (ADAMS Accession No. ML081480201)
06/05/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating Units 2 and 3, Reply to Request for Additional Information Regarding License Renewal Application - Operating Experience (ADAMS Accession No. ML081630202)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
06/11/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point, Units 2 & 3, Reply to Request for Additional Information Regarding License Renewal Application Structures - Clarification on Responses (ADAMS Accession No. ML081760264)
06/11/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, Indian Point Nuclear Generating, Units 2 and 3 - Amendment 5 to License Renewal Application (ADAMS Accession No. ML081760265)
06/11/2008	Press Release-I-08-040: NRC to Discuss Preliminary Results of Inspection for Indian Point License Renewal Application on June 18 (ADAMS Accession No. ML081630147)
06/27/2008	05/19/2008 Summary of Telephone Conference Call Between the NRC and Entergy Nuclear Operations, Inc., Concerning the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application - Submerged Cables (ADAMS Accession No. ML081770331)
06/27/2008	05/30/2008 Summary of Telephone Conference Call Between the NRC and Entergy Nuclear Operations, Inc., Concerning Responses to Request for Additional Information Related to the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application (ADAMS Accession No. ML081720557)
07/09/2008	06/02/2008 Summary of Telephone Conference Call Between the NRC and Entergy Nuclear Operations, Inc., Concerning Response to Audit Item Related to the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application - Bolted Connections (ADAMS Accession No. ML081770527)
07/25/2008	07/08/2008 Summary of Telephone Conference Call Between the NRC and Entergy Nuclear Operations, Inc., Related to the Indian Point, Unit 2 & 3, License Renewal Application Concerning Reactor Vessel Neutron Embrittlement & Submerged Cables (ADAMS Accession No. ML082050612)
07/29/2008	06/24/2008 Summary of Telephone Conference Call Between the NRC and Entergy Nuclear Operations, Inc., Related to the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application - Balance of Plant (ADAMS Accession No. ML082050276)
08/01/2008	Letter from NRC to Entergy Nuclear Operations, Inc., Inspection Report IR 05000247-08-006 and 05000286-08-006 on 01/28/20080 - 02/01,11-14/08, 03/31/ - 04/02/08, 6/02-06, 18/08 for Indian Point, Units 2 and 3 (ADAMS Accession No. ML082140149)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
08/14/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, "Indian Point, Units 2 and 3 - Additional Information re License Renewal Application - Structural OE Clarifications, Clarifications for Electrical RAIs and Audit Questions, License Renewal Application Amendment" (ADAMS Accession No. ML082350071)
09/02/2008	Letter NRC to Entergy Nuclear Operations, Inc, "Revision of Schedule for the Conduct of Review of the Indian Point Nuclear Generating, Units 2 & 3, License Renewal Application" (ADAMS Accession No. ML082400214)
09/02/2008	Press Release-08-160: NRC Extends Review Schedule for Indian Point License Renewal Application" (ADAMS Accession No. ML082460633)
09/24/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, "Indian Point Units 2 & 3, Additional Information Regarding License Renewal Application - Reactor Vessel Fluence Clarification" (ADAMS Accession No. ML082760402)
10/24/2008	09/08/2008 Summary of Telephone Conference Call Between the NRC and Entergy Nuclear Operations, Inc., Concerning Additional Information Related to the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application—Operating Experience And LRA Section 3.5.2.2 (ADAMS Accession No. ML082950776)
10/28/2008	09/15/2008 Summary of Telephone Conference Call Between the NRC and Entergy Nuclear Operations, Inc., Pertaining to the Indian Point Nuclear Generating Units 2 and 3, License Renewal Application – Reactor Vessel Neutron Embrittlement (ADAMS Accession No. ML082970810)
11/06/2008	Letter from Entergy Nuclear Operations, Inc., to NRC, "Additional Information Regarding License Renewal Application - Operating Experience Clarification" (ADAMS Accession No. ML083220425)
12/22/2008	Letter from NRC to Entergy Nuclear Operations, Inc., regarding Notice Of Availability of the Draft Supplement 38 to the Generic Environmental Impact Statement For License Renewal of Nuclear Plants Regarding Indian Point Nuclear Generating Unit Nos. 2 and 3 (ADAMS Accession No. ML083390523)
12/30/2008	Letter from NRC to Entergy Nuclear Operations, Inc., regarding Request for Additional Information for the Review of the Indian Point Nuclear Generating Unit Nos. 2 and 3, License Renewal Application – Miscellaneous Items (ADAMS Accession No. ML083640270)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
01/13/2009	Letter from NRC to Entergy Nuclear Operations, Inc., "Audit Reports regarding the License Renewal Application for the Indian Point Units 2 and 3, License Renewal Application" (ADAMS Accession No. ML083540625)
01/13/2009	"Scoping and Screening Methodolgy Audit Trip Report For Indian Point, Units 2 and 3" (ADAMS Accession No. ML083540648)
01/13/2009	"Audit Report For Plant Aging Management Programs and Reviews for Indian Point, Units 2 and 3" (ADAMS Accession No. ML083540662)
01/15/2009	Letter from NRC to Entergy Nuclear Operations, Inc., "Safety Evaluation Report with Open Items Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3" (ADAMS Accession No. ML090060045)
01/15/2009	"Safety Evaluation Report with Open Items Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3" (ADAMS Accession No. ML090150571)
01/16/2009	Press Release 09-012: NRC Issues Safety Evaluation Report with Open Items for Indian Point Nuclear Plant License Renewal Application (ADAMS Accession No. ML090160217)
02/04/2009	12/17/2008 Summary of Telephone Conference Call Between the NRC and Entergy Nuclear Operations, Inc., Concerning Draft Request for Additional Information Pertaining to the Indian Point Nuclear Generating Unit Nos. 2 and 3, LRA-Open Items (ADAMS Accession No. ML090300033)
01/27/2009	Letter from Entergy Nuclear Operations, Inc., to NRC, "Indian Point, Units 2 & 3, Reply to Request for Additional Information - Miscellaneous Items" (ADAMS Accession No. ML090420455)
03/13/2009	Summary of Telephone Conference Calls Held Between February 9 and 17, 2009, between NRC and Entergy Nuclear Operations, Inc., Concerning Indian Point Nuclear Generating Unit Nos. 2 and 3, License Renewal Application-Status of Open Items (ADAMS Accession No. ML090710320)
03/25/2009	03/02/2009 Summary of Telephone Conference Call Held Between NRC and Entergy Nuclear Operations, Inc., Concerning Draft Request for Additional Information Pertaining to the Indian Point, Units 2 & 3, License Renewal Application - Open Items (ADAMS Accession No. ML090760748)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
03/12/2009	Letter from Entergy Nuclear Operations, Inc., to NRC, "Indian Point Nuclear Generating Units 2 and 3 - Response to Safety Evaluation Report with Open Items Related to the License Renewal" (ADAMS Accession No. ML090830518)
03/04/2009	"Transcript of the ACRS Plant License Renewal Subcommittee Meeting (Indian Point), March 04, 2009" (ADAMS Accession No. ML090840402)
04/03/2009	Letter from NRC to Entergy Nuclear Operations, Inc., "Request for Additional Information for the Review of the Indian Point Nuclear Generating Unit Nos. 2 and 3, License Renewal Application - Open Items" (ADAMS Accession No. ML090920150)
04/09/2009	04/01/09 Summary of Telephone Conference Call Between the U.S. Nuclear Regulatory Commission and Entergy Nuclear Operations, Inc., Concerning Draft Request for Additional Information Pertaining to the Indian Point Nuclear Generating Units 2 and 3 License Renewal Application – Open Items" (ADAMS Accession No. ML090930495)
05/06/2009	"Certified Minutes of the Plant License Renewal Subcommittee Regarding Indian Point Nuclear Generating Units 2 and 3 on March 4, 2009" (ADAMS Accession No. ML091260359)
05/01/2009	Letter from Entergy Nuclear Operations, Inc., to NRC, "Indian Point, Units 2 & 3, Reply to Request for Additional Information - Open Items" (ADAMS Accession No. ML091320338)
06/10/2009	04/27/09 Summary of Telephone Conference Call Held Between the NRC and Entergy Nuclear Operations, Inc., Concerning RAIs Pertaining to the Indian Point Nuclear Generating Unit Nos. 2 and 3, License Renewal - Open Items (ADAMS Accession No. ML091350334)
05/20/2009	Letter from NRC to Entergy Nuclear Operations, Inc., "Indian Point Nuclear Generating Unit Nos. 2 and 3, RAI for the Review of License Renewal Application" (ADAMS Accession No. ML091380185)
06/04/2009	"ACRS Meeting with the U.S. Nuclear Regulatory Commission, - June 4, 2009, Slides" (ADAMS Accession No. ML091390631)
05/15/2009	Letter from Entergy Nuclear Operations, Inc., to NRC, "Indian Point, Units 2 & 3 – Amendment 8 to License Renewal Application" (ADAMS Accession No. ML091460051)

APPENDIX B: CHRONOLOGY	
Date	**Subject**
06/12/2009	Letter from Entergy Nuclear Operations, Inc., to NRC, "Indian Point Nuclear Generating, Units 2 & 3 - Reply to Request for Additional Information Regarding Offsite Power, Refueling Cavity, and Unit 2 Auxiliary Feedwater Pump Room Fire Event" (ADAMS Accession No. ML091750166)
06/30/2009	Letter from Entergy Nuclear Operations, Inc., to NRC, "Indian Point Units 2 & 3 - Amendment 8, Revision 1 to License Renewal Application" (ADAMS Accession No. ML091880426)
07/27/2009	Letter from Entergy Nuclear Operations, Inc., to NRC, "Questions Regarding Buried Piping Inspections, Indian Point Nuclear Generating Unit Nos. 2 & 3" (ADAMS Accession No. ML092330120)
08/06/2009	Letter from Entergy Nuclear Operations, Inc., to NRC, "Additional Information Regarding License Renewal Application – IPEC RAI 2.3A.3.11-1 and Buried Piping and Tanks Inspection Clarifications, Indian Point Nuclear Generating Unit Nos. 2 & 3" (ADAMS Accession No. ML092250166)
08/11/2009	07/22/09 Summary of Telephone Conference Call Held Between the NRC and Entergy Nuclear Operations, Inc., Concerning the Indian Point Nuclear Generating Unit Nos. 2 and 3, License Renewal Application – Buried Piping and Tanks Inspection Program (ADAMS Accession No. ML092190003)
08/11/2009	08/04/09 Summary of Telephone Conference Call Held Between the NRC and Entergy Nuclear Operations, Inc., Concerning Information Provided by Entergy in a Letter dated November 16, 2007 (ADAMS Accession No. ML092190197)
08/11/2009	08/05/09 Summary of Telephone Call Held Between the NRC and Entergy Nuclear Operations, Inc., Concerning Information Provided by Entergy in a Letter dated July 27, 2009 (ADAMS Accession No. ML092190201)
08/11/2009	Safety Evaluation Report Related to the License Renewal of Indian Point Nuclear Generating Unit Nos. 2 and 3 (ADAMS Accession No. ML092240268)
09/23/2009	Report on the Safety Aspects of the License Renewal Application for the Indian Point Nuclear Generating Unit Nos. 2 and 3 (ADAMS Accession No. ML092590684)

Appendix C

APPENDIX C

PRINCIPAL CONTRIBUTORS

This appendix lists the principal contributors for the development of this safety evaluation report (SER) and their areas of responsibility.

APPENDIX C: PRINCIPAL CONTRIBUTORS	
Name	**Responsibility**
Kimberly Green	Safety Project Manager
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Devender Reddy	Scoping and Screening Methodology
Matthew Homiak	Scoping and Screening Methodology
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Duc Nguyen	Aging Management Programs and Reviews
Surinder Arora	Aging Management Programs and Reviews
Peter Wen	Time-Limited Aging Analyses
Qi Gan	Time-Limited Aging Analyses
On Yee	Time-Limited Aging Analyses
John Tsao	Time-Limited Aging Analyses
Carol Nove	Aging Management Programs
Barry Elliot	Reactor Vessel Neutron Embrittlement
Lambros Lois	Reactor Vessel Fluence
Benjamin Parks	Reactor Systems
Diane Jackson	Reactor Systems
Stanley Gardocki	Mechanical Systems
Steve Jones	Mechanical Systems
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Name	**Responsibility**
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Janak Raval	Heating, Ventilation and Air Conditioning
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Hans Ashar	Structures
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Timothy Lupold	Nickel Alloy Programs
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Kenneth Chang	Management Oversight
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Richard Morante, Brookhaven National Laboratory (BNL)	Aging Management Programs and Reviews
Joe Braverman, BNL	Aging Management Programs and Reviews
Mano Subudhi, BNL	Aging Management Programs and Reviews
Ken Sullivan, BNL	Aging Management Programs and Reviews

Appendix D

APPENDIX D

REFERENCES

This appendix lists the references used throughout this safety evaluation report (SER) for review of the license renewal application (LRA) for Indian Point Nuclear Generating Unit Nos. 2 and 3.

APPENDIX D: REFERENCES
American Concrete Institute (ACI) 202.2R-77
ACI 318, "Building Code Requirements for Structural Concrete"
ACI 349, "Code Requirements for Nuclear Safety-Related Concrete Structures"
American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section III, "Rules for Construction of Nuclear Power Plant Components"
ASME Boiler and Pressure Vessel Code, Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components"
ASME Code, Section XI, Appendix G, "Fracture Toughness Criteria for Protection Against Failure"
ASME Code Case N-512, "Assessment of Reactor Vessels with Low Upper-Shelf Charpy Impact Energy Levels"
American National Standards Institute (ANSI) B31.1, "Power Piping"
American Society for Testing Materials (ASTM) Special Technical Publication 1005, "Distillate Fuel: Contamination, Storage and Handling"
ASTM D 445, "Standard Test Method for Kinematic Viscosity of Transparent and Opaque Liquids"
ASTM D 4951, "Standard Test Method for Determination of Additive Elements in Lubricating Oils by Inductively Coupled Plasma Atomic Emission Spectrometry"
ASTM D 96, "Standard Test Method for Water and Sediment in Crude Oil by Centrifuge Method (Field Procedure)"
ASTM E 185, "Standard Practice for Design of Surveillance Programs for Light-Water Moderated Nuclear Power Reactor Vessels"

APPENDIX D: REFERENCES
Branch Technical Position (BTP)_APCSB 9.5-1, "Guidelines for Fire Protection for Nuclear Power Plants"
American Society for Metals, "Metals Handbook® Desk Edition," Copyright 1985
ASTM C 33, "Standard Specification for Concrete Aggregates"
ASTM C 289, "Standard Test Method for Potential Alkali-Silica Reactivity of Aggregates (Chemical Method)"
ASTM C 227, " Standard Test Method for Potential Alkali Reactivity of Cement-Aggregate Combinations (Mortar-Bar Method)"
ASTM C 295, "Standard Guide for Petrographic Examination of Aggregates for Concrete'
ASTM D 96, "Standard Test Method for Water and Sediment in Crude Oil by Centrifuge Method (Field Procedure)"
ASTM D 445, "Standard Test Method for Kinematic Viscosity of Transparent and Opaque Liquids (and the Calculation of Dynamic Viscosity)"
ASTM D 975, "Standard Practice for Manual Sampling of Petroleum and Petroleum Products"
ASTM D 1796, "Standard Practice for Manual Sampling of Petroleum and Petroleum Products"
ASTM D 2709, "Standard Practice for Manual Sampling of Petroleum and Petroleum Products"
ASTM D 2276, "Standard Test Method for Particulate Contaminant in Aviation Fuel by Line Sampling"
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APPENDIX D: REFERENCES
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APPENDIX D: REFERENCES
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APPENDIX D: REFERENCES
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APPENDIX D: REFERENCES
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