IPRenewal NPEmails

From: Kimberly Green
Sent: Friday, December 12, 2008 12:21 PM
To: STROUD, MICHAEL D; Tyner, Donna
Cc: James Medoff; Stanley Gardocki; James Davis; Jerry Dozier; IPRenewal NPEmails
Subject: Draft RAIs on various subjects
Attachments: Draft RAIs for Open Items 12-12-08 Sent to Applicant.doc

Mike and Donna,

Attached are draft RAIs on various subjects. Please look over and let me know if you require a telephone conference call. The purpose of the call will be to obtain clarification on the staff's request.

Thanks,
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INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 AND 3
LICENSE RENEWAL APPLICATION
DRAFT REQUEST FOR ADDITIONAL INFORMATION (D-RAI)

D-RAI-2.3A.4.2-2 (Unit 2)

Indian Point Nuclear Generating Unit No. 2 (IP2) UFSAR Section 14.1.10, "Excessive Heat Removal Due To Feedwater System Malfunctions," explains in the case of excessive feedwater (FW) flow resulting from an accidental full opening of one FW control valve, the resulting transient is similar to, but less severe than the hypothetical steamline break transient described in Section 14.2.5. Therefore, the failure is bounded by the analysis presented in Section 14.2.5. UFSAR Section 14.2.5.6, Containment Peak Pressure for a Postulated Steam Line Break, specifically indicates that for IP2 the applicant takes credit for the main FW stop valves, BFD-5's, closing within 120 seconds, in the event of the failure of the main FW control valve.

In response to a telephone conference call the staff had with the applicant on March 7, 2008 (ADAMS Accession number ML080840568), the applicant revised its response to RAI 2.3A.4.2-1. In its amended response, dated March 24, 2008, the applicant reiterated that the FW valves credited for FW isolation are safety-related. This response did not specifically include FW isolation valves, BFD-5s, by name, and they are not included within the boundary flags for system scope, nor highlighted on license renewal drawings for having an intended function in accordance with 10 CFR 54.4(a)(1).

The staff requests the applicant to: a) justify the exclusion of these isolation valves, BFD-5's, from the scope of license renewal in accordance with 10 CFR 54.4(a)(1), and b) verify whether a similar issue to Unit 3 exists for Unit 2 as stated in the following RAI (RAI 2.3B.4.2-2) for Unit 3, which credits closure of BFD-5's and BFD-90's valves in the event of a main steam line break on a high steam flow safety injection logic, which would require not only the inclusion of BFD-5's but also BFD-90's within scope per 10 CFR 54.4(a)(1).

D-RAI 2.3B.4.2-2 (Unit 3)

Similar to the issue stated in the above RAI for Unit 2 (D-RAI-2.3A.4.2-2), a comparable issue applies for FW isolation valves for Unit 3. However, the Unit 3 analysis differs slightly from Unit 2 to include the FW isolation valves (BFD-90's) associated with the FW regulating bypass valves. UFSAR Section 14.2.5, "Rupture of a Steam Pipe," states that in the event of a main steam line break incident, the motor-operated valves (MOVs) associated with each of the FW regulating valves (FRVs) will also close. The mechanical stroke time of 120 seconds to close these associated MOVs has been analyzed and is acceptable. In addition, license renewal drawing 9321-20193 shows a "HIGH STEAM FLOW SI LOGIC" signal goes to these motor-operated isolation valves. UFSAR Section 14.2.5.1 states that redundant isolation of the main FW lines is necessary, because sustained high FW flow would cause additional cooldown. Therefore, in addition to the normal control action which will close the main FW valves, any safety injection signal will rapidly close all FW control valves (including the motor-operated block valves and low-flow bypass valves), trip the main FW pumps, and close the FW pump discharge valves.

The motor-operated block valves shown on the license renewal drawings are BFD-5's and BFD-90's for the main FRVs, and the low flow bypass regulating valves, respectively. The FW isolation valves, BFD-5s and BFD-90s, are not shown to be included within the system boundary flags for system scope, nor highlighted on LRA drawings for having an intended function in accordance with 10 CFR 54.4(a)(1). In its amended response, dated March 24, 2008, the applicant did not specifically include these FW isolation valves, BFD-5s and BFD-90s, by name.

The staff requests the applicant to justify the exclusion of these isolation valves, BFD-5s and BFD-90s, from scope of license renewal in accordance with 10 CFR 54.4(a)(1).

D-RAI-2.3A.4.5-2 (Unit 2)

In LRA Section 2.3.4.5, IP2 AFW Pump Room Fire Event, the applicant describes their methodology for mitigating the consequences of a fire event in the auxiliary feedwater (AFW) room by the use of structures and components (SCs) located in Unit 1, which has been retired. The applicant credits the supply of water from the Unit 1 condensate storage tanks (CSTs) to the Unit 2 condenser. The applicant did not fully describe all the SCs utilized to perform this function in the LRA, which resulted in a request for additional information, RAI 2.3A.4.2-1. In a letter dated January 4, 2008, the applicant responded that the majority of the components in this flow path were included in scope and subject to an aging management review (AMR) as required by 10 CFR 54.4 (a)(2) except for a few outdoor components. The applicant proposed to revise the LRA to include the Unit 1 CSTs in scope and subject to an aging management review (AMR). However, the applicant did not alter its methodology imposed for exclusion of SCs from an AMR in this flow path.

In the LRA section for the AMR results for the steam and power conversion systems, Section 3.4.2, the applicant describes its methodology for excluding components from an AMR:

> The IP1 condensate storage tanks are only subject to intermittent service. Therefore, a daily check of tank level and intermittent usage of piping and valves from the IP1 CSTs to the IP2 condenser confirm availability. Significant degradation that could threaten the performance of the intended functions will be apparent in the period immediately preceding the event and corrective action will be required to sustain continued operation.
>
> The use of this approach for confirmation of the integrity of systems required to perform the post-fire intended function of supplying water to the steam generators is analogous to the approach used for confirmation of condenser integrity in the MSIV leakage pathway of boiling water reactors. In this MSIV leakage pathway scenario, the intended function of the condenser (holdup and plateout of MSIV leakage) is continuously confirmed by normal plant operation. The use of this approach has been accepted by the staff (NUREG-1796, Dresden and Quad Cities SER, Section 3.4.2.4.4, and NUREG-1769, Peach Bottom SER, Section 3.4.2.3), where they concluded that main condenser integrity is continually verified during normal plant operation and no aging management program is required to assure the post-accident intended function.

The staff reviewed the applicant’s citing of the Peach Bottom SER mentioned in its application for precedence. The Peach Bottom SER cites the following basis:

> No aging effects were identified by the AMR for the main condenser components made of carbon steel, stainless steel, or titanium in steam, reactor coolant, or raw water environments. These materials have successfully performed as main

condenser materials at other plants. Further, the applicant has concluded that aging management of the main condenser is not required based on analysis of materials, environments, and aging effects.

Peach Bottom did include the components of the condenser in scope and subject to an AMR. It was during its aging management evaluation it determined that no aging management program (AMP) was necessary. Hence, it did not exclude these components from an AMR as the Indian Point methodology is attempting to do. The staff reviewed the applicant's citing of Dresden/Quad City SER and determined the SER basically follows the same methodology as Peach Bottom, i.e., the condenser was initially included in scope and subject to an AMR. Then, during the aging management evaluation, it determined no aging affects required an AMP. Therefore, the precedence Indian Point references does not sustain its methodology, and in fact, reinforces the staff's position that the applicant must first determine which SCs are within the scope of license renewal in accordance with 10 CFR 54.4 and require an AMR in accordance with 10 CFR 54.21.

The staff requests that the applicant provide the staff with additional justification for excluding other passive, long-lived components in the subject flow path from an AMR.

D-RAI 3.0.3.3.3-1

In the LRA, the applicant stated that the existing program will be enhanced to include the minimum wall thickness for the new heat exchangers added to the scope of the program, and to specify that if visual examination is performed, the acceptance criterion is "no unacceptable signs of degradation." These acceptance criteria for visual examination are not clear and appear to be subjective. Therefore, the staff requests that Entergy clarify, in quantitative terms, what acceptance criteria are used for the visual examination of the heat exchanger tubes.

D-RAI 3.0.3.3.4-1

LRA Table B-2 identifies AMP B.1.18, Inservice Inspection Program as a plant-specific condition monitoring program for the applications. The staff notes that Entergy has committed to enhance the "detection of aging effects" program element of the Inservice Inspection Program to revise the AMP to provide for periodic visual inspections of lubrite sliding supports used in the Steam Generator (SG) supports and reactor coolant pump (RCP) supports in order to confirm the absence of aging effects. Please specify (1) which aging effects and parameters will be monitored for by the visual examinations, (2) the types of visual examinations (e.g., VT-1, EVT-1, VT-2, or VT-3), (3) inspection frequency and sample size for the visual examination method that will be used to monitor for aging, (4) the acceptance criteria that will be used to evaluate the examination results, and (5) the corrective action or actions that will be implemented in the inspection results do not conform to the acceptance standard(s) for these components.

D-RAI 3.0.3.3.4-2

The staff notes that the "corrective actions" program element for AMP B.1.18, Inservice Inspection Program, credits only the corrective actions in the ASME Code Section XI, Articles IWA-4000 and IWA-7000 as the corrective action criteria for the program. The ASME Code Section XI editions of record for IP units are the 2001 Edition of the ASME Code Section XI inclusive of the 2003 Addenda for IP2 and the 1989 Edition of the ASME Code Section XI, with no addenda for IP3. The staff noted that Entergy did not credit component-specific corrective action criteria in ASME Section XI, Article IWB-4000/7000 for Class 1 components, Article IWC-

4000/7000 for Class 2 components, Article IWD-4000/7000 Class 3 components, or Article IWF-4000/7000 for ASME Code Class component supports as being within the scope of the “corrective action” program element for this AMP. Clarify whether the content of the “corrective actions” program element was intended to mean that Entergy will implement the corrective action provisions in the ASME Code Section XI, Subsections IWA, IWB, IWC, IWD, and IWF that are applicable to the component Code Class in the applicable ASME Code Section XI edition of record.

D-RAI 3.0.3.3.7-1

LRA Table B-2 identifies AMP B.1.29, Periodic Surveillance and Preventative Maintenance Program, as an existing, plant-specific condition monitoring program for the LRA. NUREG-1800, Revision 1, “Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants” (SRP-LR), Appendix A, Section A.1.2.2 states that aging management programs for license renewal applications (LRAs) are to be defined in terms of the 10 program elements that are provided in Table A-1 of the same appendix.

The staff notes that the applicant plans to enhance the “scope of program,” “parameters monitored,” “detection of aging effects,” and “acceptance criteria” program elements for this AMP to develop the program activities in the future (Commitment 21). Technical Specification (TS) 5.5.2 for IP2 and TS 5.5.2 for IP3 provide TS preventative maintenance and surveillance requirements.

1. The staff requests that Entergy supplement the “scope of program” program element to clearly identify the systems and components that are within the scope of this AMP. The staff also requests that Entergy clarify whether any of the components in TS 5.5.2 for IP2 and TS 5.5.2 for IP3 are within the scope of this AMP, and if so, whether the inspection and preventative maintenance requirements in these TS sections are credited for aging management of the components.

2. The program element did not clearly establish which type of non-visual NDE method (volumetric examination by UT, RT, or ET or surface examination by MT or PT) or visual method (i.e., EVT-1, VT-1, VT-2, or VT-3) would be credited for each of the aging effects that the program monitors for. In addition, it is not clear whether flexing of the elastomeric components in the circulating water system and emergency diesel generator exhaust system would be coupled to the visual examinations of the components, as it was proposed for other elastomeric components within the scope of the AMP.

   The staff requests a more definitive discussion on the specific inspection methods (UT, RT, ET, EVT-1, VT-1, VT-2, or VT-3) to detect the parameters that are associated with the aging effects the AMP monitors for. The staff also requests that Entergy clarify whether physical manipulation (i.e., flexing) of the elastomeric components in the circulating water system and emergency diesel generator exhaust system are credited under the AMP.

3. The program element for the AMP did not provide any discussion on how the data from the inspections performed under the “detection of aging effects” program element would be collected, quantified, or evaluated against applicable acceptance criteria, and used to make predictions related to degradation growth or to schedule re-inspections of the components. The staff requests a more definitive discussion on how the inspection results or physical manipulation (flexing) results (for elastomers) will be collected and

quantified, or evaluated against applicable acceptance criteria, and used to make predictions related to degradation growth or to schedule re-inspections or repairs of the components.

4. The program element for the AMP only states that “acceptance criteria are defined in specific inspection and testing procedures and that these acceptance criteria include appropriate temperature, no significant wear, corrosion, cracking, change in material properties (for elastomers), and significant fouling based on applicable intended functions established by plant design basis. The program element discuss does not clearly identify the quantitative or qualitative criteria that will be used to assess the inspection results or reference the regulatory-based documents or standards that contain these criteria. The staff requests a clarification on the specific quantitative or qualitative acceptance criteria that will be used to evaluate the results of the specific inspection methods or physical manipulation methods (for elastomers) that are implemented under this AMP.

5. With respect to operating experience and the discussion on the NaOH tanks and recirculation pumps, clarify whether the term “no deficiencies” means that no evidence of loss of material (by corrosion, erosion, wear, or other mechanisms) was detected in the components or whether the meaning is that some amount of age-related degradation had been detected in the components and the amount of cracking or loss of material (wall loss) was found to be acceptable when compared to appropriate acceptance standards.

   With respect to the discussion on the IP2 and IP3 emergency diesel generators, the security diesel generator, and the IP3 Appendix R fire protection diesel generator, clarify whether the statements “no unacceptable loss of material” and “no significant corrosion or wear” mean that no loss of material (by corrosion, erosion, wear, or other mechanisms) was detected in the components or that some loss of material was detected in the components and the amount of loss of material was found to be acceptable when compared to appropriate acceptance standards. If some degradation was detected in these components and the amount of degradation was in conformance with the applicable acceptance criteria, clarify whether scope of the AMP included appropriate reinspections of the components in order to account for potential degradation growth of the components.

D-RAI 3.1.2.1.2-1

Entergy provided a response to Audit Item 201 in its letter dated December 18, 2007, and amended LRA AMR 3.1.1-52 to justify why loss of preload due to stress relaxation, loss of materials due to wear, and cracking due to stress corrosion cracking (SCC) are not aging effects requiring management for the SA-193, Grade B7 bolting that is used in the IP2 and IP3 reactor coolant systems. SRP-LR Appendix A, Section A.1.2.1, Item 7, states that leakage past bolting is not to be treated as an abnormal event and used as a basis for omitting an aging effect as an applicable aging effect requiring management. Therefore, the staff finds that the response to Audit Question 201 does not provide an adequate basis for concluding that loss of material due to wear, cracking due to SCC, or loss of preload due to stress relaxation are not applicable aging effects for the SA-193 Grade B7 bolting used at IP2 and IP3:

1. In regard to loss of material due to wear, if Entergy has experienced past bolt thread failures as a result of wear of its SA-193, Grade B7 bolting components, consistent with the staff's position in SRP-LR Appendix A Section A.1.2.1, Item 7 basis, leakage past the bolting is possible and should not be treated as an abnormal event, and loss of material due to wear is an applicable aging effect for these bolted connections. Clarify why the LRA treated it as an abnormal event.

2. In regard to loss of preload due to stress relaxation, Entergy cites a stress relaxation threshold for SA-193, Grade B7 bolts of 7000ºF. Yet the threshold used in the industry's own aging management screening basis document (EPRI Tools) cites this threshold as 700ºF not 7000ºF. In addition, the stress intensity items and footnotes for ASME Class 1 bolting in Table 4 of the ASME Code, Section II clearly identify that stress relaxation thresholds for SA-193 Grade B7 bolting are dependent on bolt size and this ASME Code Section II table lists thresholds for stress relaxation for these materials as low as 500ºF. Thus, stress relaxation could possibly occur in SA-193 Grade B7 bolting if they are exposed to service temperatures in excess of 500ºF. Entergy has not demonstrated that the service temperatures for the SA-193 Grade B7 bolting in the RCS would not be less than 500ºF and thus has not provided a sound basis on whether the loss of preload due to stress relaxation is an issue for its SA-193 Grade B7 bolting. Clarify why the highest temperatures were used instead of the lowest.

3. In regard to cracking due to SCC, Entergy states that SCC is not an aging mechanism that could induce cracking in these bolting materials because the applied loads are less than 100 ksi. Yet in the staff's safety evaluation on WCAP-14574-NP-A, "Acceptance for Referencing of Generic License Renewal Program Topical Report Entitled 'License Renewal Evaluation: Aging Management Evaluation for Pressurizers,'" dated October 26, 2000, the staff based its position on whether or not SCC would be applicable to SA-193, Grade B7 bolting based on the procured yield strength being less than 150 ksi or procured Rockwell C hardness values being less than a value of 32. Provide a basis on why SCC would not need to be considered for the SA-193, Grade B7 bolting.

D-RAI 3.1.2.1.3-1

The applicant's response to Audit Question 207, dated December 18, 2007, the applicant states that a One-Time Inspection will be used to verify the effectiveness of the Water Chemistry Control Program – Primary and Secondary in managing cracking of the pressurizer spray head couplings and locking bars. The applicant indicated that it did not need to amend the applicable AMRs in LRA Table 3.1.2-3-IP2 and 3.1.2-3-IP3 for the these components to credit its One-Time Inspection Program (either directly or through a reference in the AMR to LRA Footnote 104) for verification of the effectiveness of the Water Chemistry Control Program – Primary and Secondary in managing cracking of these non-Code Class components. Justify your basis for not amending the applicable AMRs to reflect that the One-Time Inspection Program is being credited in conjunction with the Water Chemistry Control Program – Primary and Secondary to manage cracking in these components.

D-RAI 3.1.2.1.6-1

SRP-LR Appendix A, Section A.1.2.1, item 7 states that "leakage from bolted connections should not be considered as abnormal events. Although bolted connections are not supposed to leak, experience shows that leaks do occur, and the leakage could cause corrosion. Thus, the aging effects from leakage of bolted connections should be evaluated for license renewal."

In Entergy's response to Audit Question 206, Entergy has taken the position that loss of material due to erosion is not an applicable aging effect for the SG secondary manway and handhold covers because erosion of the component would only occur if leakage had occurred past the bolted connections in the covers and because such leakage would be quickly noted and corrected, and as such is an abnormal occurrence for the facility.

Entergy's response to Audit Question 206 is inconsistent with SRP-LR Appendix A, Section A.1.2.1, item 7. The staff requests that Entergy explain why loss of material due to erosion is not an aging effect requiring management for the SG secondary manway and handhold covers.

<u>D-RAI 3.1.2.2.7.2-1</u>

Part A - The staff notes that the Inservice Inspection Program (as given in LRA Section B.1.18) is credited, in part, as an acceptable plant-specific condition monitoring program for the management of cracking in ASME Code Class 1 components, including ASME Code Class 1 cast austenitic stainless steel (CASS) components. However, the staff also notes that the inspections credited under this program might be either ultrasonic test (UT) examinations or enhanced VT-1 visual examinations. If UT examinations are credited for aging management of reduction of fracture toughness in the CASS components, clarify how the UT technique selected for the examination will be capable of differentiating between UT signals that derive from flaws or cracks in the CASS materials from those the derived from UT background noise signals as a result of the complexity of the CASS microstructure or component geometry.

Part B - The staff determined that Entergy credits its Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program in part to manage cracking in the non-ASME Code Class CASS pressurizer spray head. The staff also notes that the applicant's program includes a flaw evaluation methodology for CASS components that are susceptible to thermal aging embrittlement, and that alternatively, this AMP may credit UT or enhanced VT-1 visual examinations as an indirect basis for managing loss/reduction of fracture toughness as a result of thermal aging. However, the staff notes that the applicant's program is not specifically credited for the management of cracking in CASS components. The staff requests that Entergy justify its basis for crediting AMP B.1.37, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program, to manage and detect cracking in the CASS pressurizer spray heads at IP2 and IP3, particularly when GALL AMP XI.M12 only credits this type of program for management of reduction or fracture toughness in CASS components and when the program may not actually be performing inspections of these components (i.e., the program has the option only to do the flaw tolerance evaluation without implementation of either a UT or EVT-1 examination).

<u>D-RAI 3.1.2-1 Nickel Alloy AMRs</u>

Part A – Clarify whether the following components at IP2 or IP3 are fabricated from Alloy 600 base metal materials or welded with Alloy 182 or Alloy 82 filler metal materials: (1) control rod drive (CRD) housing-CRD nozzle welds, (2) upper reactor vessel closure head (RVCH) head vent nozzle-to-RVCH welds, (3) CRD housing penetration CETNA components, (4) SG primary side instrument penetration, nozzles, safe ends, or welds

Part B - The staff notes that in the applicant's response to Audit Question 208, dated December 18, 2007, the applicant stated that the LRA Tables 3.1.2-1-IP2 through 3.1.2-4-IP2 and LRA Tables 3.1.2-1-IP3 through 3.1.2-4-IP3 include numerous AMR items for nickel-alloy components. The applicant stated that these AMR items are compared to GALL Report Items IV.A2-18 and IV.A2-19, which correspond to LRA table entries 3.1.1-31 and 3.1.1-65. The applicant stated that the AMR in LRA AMR 3.1.1-69 is only for management of cracking in the RV inlet and outlet nozzle safe-ends and the RV bottom head drain safe-ends. With respect to the AMRs on cracking of nickel alloy bottom mounted instrumentation (BMI) nozzle components, the staff notes that the response to Question 208 stated that the RV bottom head safe-ends at IP2 and IP3 are those for the RV bottom head drains. Yet the staff notes that LRA Tables 3.1.2-1-IP2 and 3.1.2-1-IP3 do not include any AMR entries for RV bottom head drains. Since your response to Audit Question 208 implies that the RV includes passive, long-lived bottom head drains, provide your basis on whether LRA Tables 3.1.2-1-IP2 and 3.1.2-1-IP3 need to be amended to include new AMRs for RV bottom head drains and their associated drain-to-bottom head welds, and if so clarify whether the bottom head drains are fabricated from Alloy 600 base metal materials or are weld to the bottom RV heads using Alloy 82 or 182 nickel alloy filler metal materials.

Part C - AMRs of LRA Tables 3.1.2-1-IP2 and 3.1.2-1-IP3, which pertain to the management of cracking in the nickel alloy RV core support pads/lugs, credit only the Water Chemistry Control Program and its Nickel Alloy Inspection Program to manage cracking of the components. The staff's recommended aging management position taken in GALL AMR IV.A2-12 for these components recommends, in part, that the Inservice Inspection Program be credited for aging management of this effect in addition to Water Chemistry Control Program – Primary and Secondary and its Nickel Alloy Inspection Program. Given the, information requested in Part A of this RAI, provide your basis why the AMRs on cracking of the nickel alloy RV core support pads/lugs, as given in LRA Tables 3.1.2-1-IP2 and 3.1.2-1-IP3, do not credit the Inservice Inspection Program along with the Water Chemistry Control Program – Primary and Secondary to manage cracking in these components. In addition, the AMRs in LRA Tables 3.1.2-4-IP2 and 3.1.2-4-IP3, which pertain to the management of cracking of the nickel alloy SG nickel-alloy primary nozzle closure rings credits only its Water Chemistry Control Program – Primary and Secondary to manage cracking due to PWSCC of the components. Provide your basis why the Inservice Inspection Program has not been credited to manage cracking in the nickel alloy RV support pads/lugs or in the nickel alloy SG primary nozzle closure rings.

D-RAI 3.4A.2.3.3-1

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 piping exposed to condensation (external) and proposed the Water Chemistry Control – Primary and Secondary Program. The GALL Report recommends using the External Surfaces Monitoring Program for managing the aging of carbon steel structures exposed to condensation (external) in GALL Chapter V, line items V.C-2 and V.E-10, Chapter VII, line item VII.1-1-b and Chapter VIII, line item VIII.H-10. The staff does not understand how the Water Chemistry Control – Primary and Secondary Program can be used to manage aging on the external surface of steel piping. Please provide a justification for using the Water Chemistry Control – Primary and Secondary Program to manage loss of material on steel piping exposed to condensation (external).