NMC
Committed to Nuclear Excellence

Point Beach Nuclear Plant
Operated by Nuclear Management Company, LLC

June 10, 2005

NRC 2005-0056
10 CFR 54

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555

Point Beach Nuclear Plant, Units 1 and 2
Dockets 50-266 and 50-301
License Nos. DPR-24 and DPR-27

Response to Safety Evaluation Report (SER) With Open Items
Regarding the Point Beach Nuclear Plant
License Renewal Application
(TAC Nos. MC2099 and MC2100)

By letter dated February 25, 2004, Nuclear Management Company, LLC (NMC), submitted the Point Beach Nuclear Plant (PBNP) Units 1 and 2 License Renewal Application (LRA). On May 2, 2005, the Nuclear Regulatory Commission (NRC) provided a draft SER identifying five (5) open items and fifteen (15) confirmatory items.

Enclosure 1 to this letter provides responses to the open items. Enclosure 2 to this letter provides responses to the confirmatory items. Enclosure 3 to this letter provides the NMC comments on the text in the draft SER.

NMC requests the opportunity to review the SER prior to final issuance to ensure incorporation of the resolution of the open items, confirmatory items, and comments.

Should you have any questions concerning this submittal, please contact Mr. James E. Knorr at (920) 755-6863.

This letter contains the following new commitment:

1. The following aging management programs will be revised to credit the One-Time Inspection Program to identify selective leaching of susceptible components:
    - Open-Cycle Cooling (Service) Water System Surveillance Program
    - Fire Protection Program
    - Systems Monitoring Program
    - Periodic Surveillance and Preventive Maintenance Program
    - Structures Monitoring Program

A093

This letter contains the following revisions to existing commitments (additions are double-underlined; deletions are strikethrough):

1. Draft SER, Appendix A, Page A-5, Commitment Number 23:

   In the Case of Sprinkler Heads, ~~Inspection~~ Test Prior to Exceeding 50-Year Service Life.

2. Draft SER, Appendix A, Page A-5, Commitment Number 29:

   Prior to Period of Extended Operation and ~~Completion will be~~ Consistent with Commitments Made in Response to NRC Bulletin 2002-02 and Requirements of NRC Order EA-03-009.

I declare under penalty of perjury that the forgoing is true and correct. Executed on June 10, 2005.

Dennis L. Koehl
Site Vice-President, Point Beach Nuclear Plant
Nuclear Management Company, LLC

Enclosure

cc: Administrator, Region III, USNRC
Project Manager, Point Beach Nuclear Plant, USNRC
Resident Inspector, Point Beach Nuclear Plant, USNRC
PSCW

ENCLOSURE 1

NMC RESPONSES TO OPEN ITEMS IN THE DRAFT SAFETY EVALUATION REPORT (SER) REGARDING POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2 LICENSE RENEWAL APPLICATION

The following information is provided in response to the Nuclear Regulatory Commission (NRC) staff's draft SER with open items regarding the Point Beach Nuclear Plant (PBNP) License Renewal Application (LRA).

The NRC staff's open items are restated below with the Nuclear Management Company (NMC) response following.

<u>NRC Open Item OI B2.1</u> (Sections 3.0.3.2.1 and 3.0.3.2.2 - ASME Section XI Inspection Programs):

Relief requests are approved by the NRC as described in 10 CFR 50.55a, Codes and Standards. Relief requests only apply to the current licensing basis (CLB) and are time-limited. Consequently, citing approved requests cannot be used as a basis for taking exception to the GALL Report since they may not be renewed. Each exception to the GALL Report must be evaluated for NRC approval based on the technical bases that are associated with aging management regardless of whether there is a current, approved, related relief request. Citing a relief request does not provide an acceptable basis to take an exception to the GALL Report.

In RAI B2.1, dated March 30, 2005, the staff requested the applicant to provide its technical bases, as they relate to aging management, and without referencing any relief requests, for the exceptions taken to ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program and ASME Code Section XI, Subsections IWE and IWL Inservice Inspection Program. This was identified as open item (OI) B2.1.

<u>NMC Response</u>:

The information requested in this open item regarding the technical basis (associated with aging management and without referencing any relief requests) for the exceptions taken in the Inservice Inspection Programs (LRA Sections B2.1.1, B2.1.2 and B2.1.3) will be provided in a future response letter from the NMC to NRC.

<u>NRC Open Item OI B2.1.4-2</u> (Section 3.0.3.2.4 - Bolting Integrity Program):

The GALL Report relies on industry recommendations for comprehensive bolting maintenance, as delineated in EPRI TR-104213 for pressure-retaining bolting and structural bolting. The applicant indicated that enhancements to the existing plant implementation documents dealing with bolted joints will be made to incorporate recommendations as deemed appropriate based upon review of NUREG-1339, EPRI NP-5769, and EPRI TR-104213. The applicant has not identified exceptions to these NUREG and EPRI documents.

In RAI 2.1.4-2, dated February 7, 2005, the staff requested the applicant to provide specific exceptions to the Bolting Integrity Program. The staff should be informed of, and approve specific exceptions to the bolting recommendations in these NUREG and EPRI documents. The applicant should provide this information for staff review and approval prior to issuance of the extended license. This was identified as open item (OI) B2.1.4-2.

<u>NMC Response:</u>

NMC initially responded to NRC Question RAI B2.1.4-2 by letter from NMC to NRC dated March 4, 2005 (NRC 2005-0024). A detailed review of the Bolting Integrity Program (LRA Section B2.1.4) was subsequently performed during the March 2005 NRC Region III License Renewal Inspection. The results of this review are documented in NRC Inspection Report 2005-005 dated May 2, 2005. During the Inspection, NMC was requested to review NUREG-1339, EPRI NP-5769, and EPRI TR-104213, and provide additional details with regards to the specific exceptions taken in the Bolting Integrity Program. The information requested in this open item, regarding the specific exceptions to the bolting recommendations in these NUREG and EPRI documents, was provided by letter from NMC to NRC dated April 8, 2005 (NRC 2005-0037).

<u>NRC Open Item OI 3.1.1-3</u> (Section 3.1.2.3.6 - Steam Generators - Aging Management Evaluation - Table 3.1.2-5):

LRA Table 3.1.2-5 identifies Notes H, 21 and J, 5 for loss of material in stainless steel, carbon steel clad with stainless steel and Alloy 600/690 materials. For these AMRs only the Water Chemistry Control Program is identified as the applicable AMP. PBNP personnel have indicated that the basis for using only the mitigative Water Chemistry Control Program is that the program does not require lack of aging effect validation if the flow is moderate or high. The staff considers this a misinterpretation of the GALL AMP. The GALL Report identifies stagnant or low flow conditions as an example of when it would be appropriate to validate the effectiveness of the Water Chemistry Control Program. The GALL Report utilizes this example to demonstrate when a validation of aging management program is appropriate, but does not define, by default, when a validation should not be used. In conditions of moderate or high flow, SSCs could have crevices or other locations of low or stagnant flow. Furthermore, all systems are shut down and flow is reduced to stagnant conditions at some point in its service life. Therefore, this was identified as open item (OI) 3.1.1-3.

NMC Response:

The line items in question are those which incorporate:

- Notes H, 21: Steam Generator (SG) Components (in contact with Primary water)
- Notes J, 5: SG Steam Flow Limiter

In discussions with the Staff, NMC indicated that being in a high flow area was one of the reasons the Water Chemistry Control Program alone was acceptable. Other reasons do apply to these situations, such as previously accepted Staff positions, operating experience, and leading indicators. Some of these reasons were previously addressed in other questions/RAIs on similar subjects. See letter NRC 2004-0071, NMC response to Audit Item 141, and letter NRC 2005-0006, NMC response to RAI 3.1-1. See discussions in draft SER for these RAIs where these responses are evaluated and accepted by the Staff.

For SG Components in contact with Primary water; *the same material types in the same* environments exist in the Reactor Vessel, the Vessel Internals, the Pressurizer, and the Class 1 Piping and Components. In all of these systems and components, loss of material is proposed to be managed with the Water Chemistry Control Program alone (and was found by the staff to be acceptable in the draft safety evaluation report (DSER)). The primary side of the SG is no different. Stainless steel and nickel alloy are corrosion-resistant materials, and the industry and plant-specific operating experience has shown that loss of material is not an active degradation mechanism on primary side components, primarily due to the strict water chemistry controls used in pressurized water reactors (PWRs). Other components in this same environment are routinely inspected (i.e., SG tubes) and these inspections would provide leading indications to the susceptibility of these materials to loss of material.

Similarly, the Steam Flow Limiter is also constructed of stainless steel, and is in a water chemistry-controlled environment. Again, industry and plant-specific operating experience shows that loss of material degradation of these types of components is not occurring. Existing inspections are performed on the secondary side of the SGs, which would also provide leading indications of susceptibility of this component to loss of material.

In summary, the Water Chemistry Control Program is adequate for managing loss of material in SG components in contact with primary water, and the steam flow limiter in contact with treated water - secondary. These components are constructed of corrosion-resistant materials, and operating experience has shown these to not be susceptible to loss of material in a water chemistry controlled environment. Additionally, other components of the same material, in these same environments, are routinely inspected which would provide leading indications for degradation of the components in question. Therefore, additional inspections to verify the effectiveness of the Water Chemistry Control Program to manage loss of material for these components are not warranted.

NRC Open Item OI 3.3-7 (Section 3.3.2.3.3 - Component Cooling Water System - Aging Management Evaluation - Table 3.3.2-2):

In LRA Table 3.3.2-2, the applicant proposed to manage cracking due to intergranular attack/intergranular stress corrosion cracking (IGA/IGSCC) of stainless steel material for heat exchanger components exposed to primary treated water with temperature greater than 480 F using the Water Chemistry Control Program. This line item cites Note 35, which states: "Component/material/environment is not addressed in the corresponding NUREG-1801 Chapter, but the component/material/environment is addressed in another NUREG-1801 Chapter." This line item references AMR line item 3.1.1-36, which provides the following discussion:

> Crack initiation growth due to SCC and flaw growth are identified as aging effects requiring management for the reactor vessel nozzle safe ends, CRD housing, and RCS components. Aging management programs credited for managing these effects are the Water Chemistry Program and ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program.

The Note implies that ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program should have also been applied to LRA Table 3.3.2-2. In RAI 3.3-7, dated March 31, 2005, the staff requested the applicant to explain this discrepancy or make a commitment to review the line item in LRA Table 3.3.2-2 to include the Inservice Inspection Program. This was identified as open item (OI) 3.3-7.

NMC Response:

The information requested in this open item, regarding whether the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program (LRA Section B2.1.1) should be credited in addition to the Water Chemistry Control Program (LRA Section B2.1.24) for the applicable Component Cooling Water System heat exchanger components line item in LRA Table 3.3.2-2, was provided in response to NRC Question RAI 3.3-7 by letter from NMC to NRC dated April 29, 2005 (NRC 2005-0043).

However, in subsequent conversations with the staff, NMC has agreed to credit the One-Time Inspection program in addition to the Water Chemistry Control Program for the heat exchangers in Table 3.3.2-2, with the understanding that these specific heat exchangers will not be inspected, but that a location with the same material/environment will be inspected to provide verification of the effectiveness of the Water Chemistry Program in this location.

NRC Open Item OI 3.5-4 (Section 3.5.2.2.1 - PWR Containments):

The discussion column of LRA Item 3.5.1-12 refers to LRA Section 3.5.2.2.1.4 for further evaluation. In the discussion, the applicant noted that the liner corrosion was identified in both units due to borated water leakage, and that ASME Code Subsection

IWE inspections would be performed in these areas. In RAI 3.5-4, dated July 27, 2004, the staff requested the applicant to provide a quantitative summary of the extent of liner corrosion found in each unit, and the corrective actions taken. The applicant was also requested to include a discussion of acceptable liner plate corrosion.

In its response, dated August 26, 2004, the applicant stated that the areas of concern include (1) the bottom containment liner plate (floor), which is covered by an eighteen-inch-thick concrete floor, and (2) SW and CCW penetrations. The penetrations have detectable pitting in the flued head region. On occasions, spilled borated water has seeped into the liner plate floor crevice. The liner plate floor receives UT measurements at selected locations.

During a meeting on February 15, 2005, the staff indicated and the applicant agreed, that this response required further clarification. The staff requested the applicant to clarify the corrective actions taken, including procedural descriptions, when loss of material is identified.

In its response, a clarification letter dated March 15, 2005, the applicant summarized that the necessity for repair has been determined on a case-by-case basis. The table provided with the response showed the liner plate base thickness reduction was as high as 46%. The response indicated that such degradation was found acceptable without repair. As this process will be continued during the period of extended operation, the staff requested additional information regarding the basic criteria used in the engineering evaluation. Specifically, the staff requested the applicant to provide a summary of the engineering evaluations performed for CAP 22754 and CAP 13912 (designated in the applicant's response table), including the type of corrosion, loads considered in the evaluation, acceptable liner strains, and strain concentration factors considered, if applicable. The applicant was also requested to provide the procedure describing the "as left" condition of the degradation. This was identified as open item (OI) 3.5-4.

<u>NMC Response</u>:

Containment liner plate engineering evaluations for CAP 22754 and CAP 13912 are provided below. The original evaluations were performed by Condition Reports (CR) CR 01-1220 and CR 01-1517, respectively. Redacted copies to remove names are provided as follows. In addition, a similarly redacted engineering judgment/evaluation, 97-10447-C001, performed by Bechtel, is enclosed.

The evaluations are based on the engineering response of the liner being dependent on strain (inch/inch) and not stress (force/area). Please refer to FSAR, page 5.1-29 and page 5.1-51 for a further discussion of the liner plate design basis and response.

Nuclear Power Business Unit

CONDITION REPORT

IF THE CONDITION MAY BE REPORTABLE OR MAY AFFECT THE OPERABILITY STATUS OF PLANT SYSTEMS OR EQUIPMENT, IMMEDIATELY INFORM THE OPERATIONS DUTY SHIFT SUPERINTENDENT (DSS).

CR 01 - 1220

Significance Level: ☐ A ☐ B ☒ C ☐ D

Applicable Unit: ☐ PB0 ☒ PB1 ☐ PB2 ☐ N/A **Date of Discovery:** 4/11/01 **Time of Discovery:** 1140

☐ **Admin Issue/Procedure Issue** ☐ **Equipment Issue** **Affected System:** CONT **Equipment ID:**

DESCRIPTION: (Describe the who, what, when, where and why of the concern, if known.)

Thickness measurements of Unit 1 liner plate CP-135 (keyway tunnel plate) taken as a result of IWE containment preservice inspection under WO 9810460 for MR 98-078 (core drill holes) indicate a base metal reduction of more than 10% of the nominal ¼ inch thickness. IWE 322.4 requires design analysis of any reduction greater than 10% of nominal thickness.

Core drilling along the liner plate was performed in the worst corroded area located at the base of the thimble tube bridge just inside the instrumentation tunnel ventilation wall. A series of 2 inch diameter overlapping holes was drilled to a depth of 2 inches into the concrete floor along the liner plate for access to the liner plate for evaluation of the corroded area. Hand drilling was performed at an angle that caused the bottom of the cut to contact the liner plate. A minimum thickness reading of 0.116 inches was reported on NDE data sheet 01U1-760E018 and 01U1-114E010.

SIGNIFICANCE: (Why this is a concern.)

ASME Section XI indication requires design evaluation prior to 200 degree F for U1R26 for adequate containment pressure barrier.

CORRECTIVE ACTIONS TAKEN: (List WO number, compensatory actions, notifications, etc.)

1. Data forwarded to Civil Design Group required design evaluation.

PROBLEM RESOLVED: ☐ Yes ☒ No | **Provide Copy of CR to Initiator After Management Review:** ☒ Yes ☐ No

RECOMMENDATIONS: (To be assessed for consideration)

References: WO 9810460, MR 98-078, NDE data sheet 01U1-760E018 | **Point of Contact:** [redacted]

Initiator: (Print Name) [redacted] | **Work Group:** ITE | **Phone Ext:** [redacted]

PBF-1552
Revision 12 12/22/99 RECD MAY 21 2001

References: NP 5.3.7, DCS 2.1.1, DCS 2.1.2, PBF-1553

BEST COPY AVAILABLE

·CR SCREENER: Screener SHALL be a SRO for Operability, Reportability, Technical Specification, or Nuclear Safety Related Issues

Date Received: 4/4/01 **Time Received:** 1240	☑ Nuclear Safety Issue (SRO only – requires SRO Screening for Nuclear Safety) ☐ Non-Nuclear Safety Issue (Unit Restart Screen ONLY)

SRO SCREENING FOR NUCLEAR SAFETY (Nuclear Safety Issues only)

Operability Basis: Containment was operable during the run as the damage was done during the shutdown. The evaluation will need to be done before going above 200°F (leaving cold shutdown)

Compensatory Actions Taken:

Operability Screener Name (print): [redacted] **SRO Signature:** [redacted]

☐ Operability Determination required to support Operability Basis   Responsible Person:

☐ Operability Determination Extended (up to 14 days)   Ops Mgr (Sign/Date) ______ / ______

Date/Time Required ______ / ______

Justification for Operability Extension:

Is the Structure, System, or Component operable? ☐ Non-Equipment ☐ Operable ☑ Inoperable (OOS)

Technical Specification / Part 21 Screen / Reportability Screen:

Is LCO entry required for this condition (check one)?	☐ Yes ☑ No	Technical Specification	
Does the condition violate a Technical Specification (check one)?	☐ Yes ☑ No	Technical Specification	
Is the condition a potential 10 CFR Part 21 concern (check one)?	☐ Yes ☑ No	☐ Requires Engineering Review	
Is the condition reportable per DCS 2.1.1 or 2.1.2 (check one)?	☐ Yes ☑ No	☐ Requires Licensing Review	

UNIT RESTART SCREEN (ALL issues – check one):

☐ None ☐ Initial System Fill/Vent ☐ Reload ☐ ORT 3 ☐ LTOP ☐ RCS Fill/Vent ☐ 140F ☑ 200F ☐ 350F ☐ 540F
☐ Criticality ☐ Steam in Secondary ☐ Grid Synchronization

Screener Comments & Recommendations: Restart issue

Screener Name: [redacted] **Signature:** [redacted] **Date/Time:** 4/4/01 1250

CORRECTIVE ACTION ASSIGNMENT – MANAGEMENT REVIEW

Group Responsible for Issue Resolution: SOS

☐ **Operability Determination Required By Management (Return CR to Control Room)**   **Date/Time:** ______ / ______

Regulatory Services Follow-up of Issue (NRC commitment) ☐ Yes ☑ No

Organizational Assessment Follow-up of Issue ☐ Yes ☑ No

Action Required: ☐ Root Cause ☐ Apparent Cause ☐ Routine Work/Plant Betterment (BCR) ☐ Document Only

Comments: Restart Issue (200°F) Requested Action: Review the Condition of the Containment Liner. Document any outstanding Issues
2) ITE : Requested Action : Determine if Drill performance was adequate and what Corrective Actions are required

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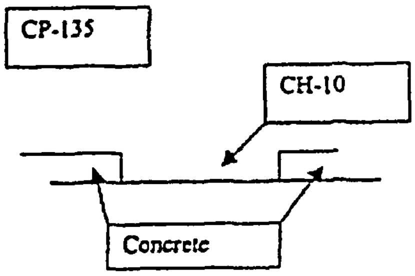
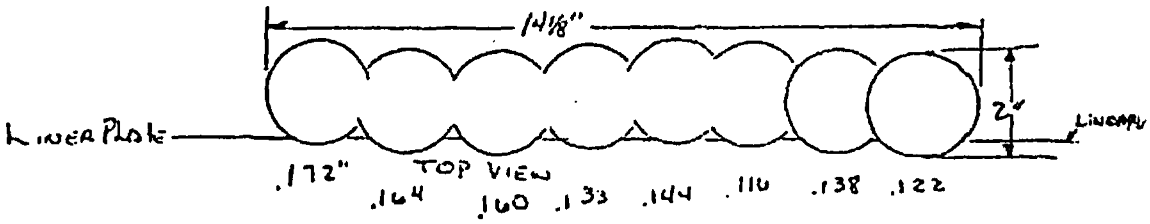
References: NP 5.3.7, DCS 2.1.1, DCS 2.1.2, PBF-1553

Component: CH-10
Data Sheet No: 01U1-760E018
Examiner(s) / Level / Date *(Signature)*: [redacted] / II 12/10/01





AVERAGE PLATE THICKNESS IN
AREA OF DRILLED HOLES .280"

Minimum Thickness : .116
Maximum Thickness: .172
Max Pitting Depth : NO PITTING NOTED

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Form NDE 760.1
Rev. 1

EVALUATION OF CR 01-1220, ACTION NUMBER 1

BACKGROUND

The liner plate function throughout the containment is to form a leak tight boundary. It is not a pressure-retaining boundary. The liner is installed right against either reinforced or prestressed concrete members designed to withstand all the design loads as specified in the FSAR including pressure inside the containment due to a large LOCA.

During the design process of the containment a ¼" plate thickness was selected for two reasons: One, is to be used as a form for wet concrete during construction; Two, is to account for some corrosion during the lifetime of the plant instead of using expensive stainless steel plate.

The liner criteria as stated in the PBNP FSAR address limiting the liner strain level and not the stress level. This is due to the fact that the liner is not a pressure-retaining boundary. For a given liner strain the stress level is the same regardless of the thickness of the liner.

EVALUATION

During the removal of 2" by 2" by 14" long concrete fill along the wall in the keyway area, as specified in MR 98-078, the drill touched the wall liner plate and shaved some of the liner. CR 01-1220 describes the shaved area and also provides UT thickness measurements of the liner at the exposed area. The average thickness measured is 0.28" with a minimum of 0.116". The 0.28" average measured thickness vs. ¼" minimum thickness required at the time of installation indicates that the liner corrosion, after 30 years of operation, is almost nil and should not be a concern in this evaluation.

Reinforced concrete walls back the liner plate in the keyway area. Under normal operating condition the liner experience no strain. Under LOCA condition and during the reactor start up, the keyway liner is strained due to rise of the air temperature and the liner temperature faster than the concrete wall temperature because of conductivity. When the concrete temperature reach the same level as the liner then the strain in the liner will be released and the stress level becomes zero. Under pressure load due to LOCA the liner in the keyway area will be strained to the same level as the concrete wall. Once the strain is known the stress in the liner can be calculated using the following formula:

$f_s = E\varepsilon$

Where: E = Modulus of Elasticity of steel.

ε = The strain of the liner plate

Since the stress in the liner is independent of the thickness of the liner, it can be concluded that there is no minimum thickness required for the liner to function as a leak tight boundary and 0.116" liner thickness is acceptable for continued service.

CONCLUSION

In accordance with the requirements of IWE-2420 of ASME Section XI the liner plate in question, the area containing degradation, should be inspected during the next two inspection periods. If the liner plate remains unchanged during the next two inspections, then no additional action is required. These additional inspections are already part of the IWE inspection program for Point Beach Nuclear Plant for preservice inspection as required by table IWE-2500-1. Therefore, I recommend that this CR be closed with no further actions required.

Nuclear Power Business Unit

CONDITION REPORT

IF THE CONDITION MAY BE REPORTABLE OR MAY AFFECT THE OPERABILITY STATUS OF PLANT SYSTEMS OR EQUIPMENT, IMMEDIATELY INFORM THE OPERATIONS DUTY SHIFT SUPERINTENDENT (DSS).

CR 01 - 1517

Significance Level: ☐ A ☐ B ☒ C ☐ D

Applicable Unit: ☐ PB0 ☒ PB1 ☐ PB2 ☐ N/A   Date of Discovery: 4/26/01   Time of Discovery: 2140

☐ Admin Issue/Procedure Issue ☐ Equipment Issue   Affected System: CONT   Equipment ID: CH-04

DESCRIPTION: (Describe the who, what, when, where and why of the concern, if known)

Thickness measurements of core drilled hole CH-04 (8 ft el) taken as a result of IWE containment preservice inspection under WO 9924295, indicates a base metal reduction of more than 10% of the nominal ½ inch thickness. IWE 322.4 requires design analysis of any reduction greater than 10% of nominal thickness.

A minimum thickness reading of 0.204 inches is reported on NDE data sheet 01U1-760E007 and 01U1-114E004 as compared to the allowable thickness of 0.225 inches for a 10% reduction. Cause is believed to be wetting and drying that occurs as result of poor moisture barrier on 8 ft el on containment resulting in general corrosion and pitting in CH-04 location. Moisture barrier replaced under WO 9804191.

SIGNIFICANCE: (Why this is a concern.)

ASME Section XI indication requires design evaluation prior to 200 degree F for U1R26 for adequate containment pressure barrier.

CORRECTIVE ACTIONS TAKEN: (List WO number, compensatory actions, notifications, etc.)

1. Data forwarded to Civil Design Group required design evaluation.

PROBLEM RESOLVED: ☐ Yes ☒ No   **Provide Copy of CR to Initiator After Management Review:** ☒ Yes ☐ No

RECOMMENDATIONS: (To be assessed for consideration)

References: WO 9924295, NDE data sheet 01U1-760E007 & 114E004, WO 9804191, IWE 322.4   Point of Contact: [redacted]

Initiator: (Print Name) [redacted]   Work Group: ITE   Phone Ext: [redacted]

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Revision 12 12/22/99

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REC'D PBE

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References: NP 5.3.7, DCS 2.1.1, DCS 2.1.2, PBF-1553

CR SCREENER: Screener SHALL be a SRO for Operability, Reportability, Technical Specification, or Nuclear Safety Related Issues

Date Received: 4/26/01
Time Received: 2237

☒ Nuclear Safety Issue (SRO only – requires SRO Screening for Nuclear Safety)
☐ Non-Nuclear Safety Issue (Unit Restart Screen ONLY)

SRO SCREENING FOR NUCLEAR SAFETY (Nuclear Safety Issues only)

Operability Basis: __________

Compensatory Actions Taken: Containment Uses Inoperable until evaluation complete

Operability Screener Name (print): __________ **SRO Signature:** __________

☐ Operability Determination required to support Operability Basis — Responsible Person: __________

☐ Operability Determination Extended (up to 14 days) — Ops Mgr (Sign/Date) __________ / ______

Date/Time Required __________ / ______

Justification for Operability Extension: __________

Is the Structure, System, or Component operable? ☐ Non-Equipment ☐ Operable ☒ Inoperable (OOS)

Technical Specification / Part 21 Screen / Reportability Screen:

Is LCO entry required for this condition (check one)? ☐ Yes ☐ No Technical Specification ______

Does the condition violate a Technical Specification (check one)? ☐ Yes ☐ No Technical Specification ______

Is the condition a potential 10 CFR Part 21 concern (check one)? ☐ Yes ☐ No ☐ Requires Engineering Review

Is the condition reportable per DCS 2.1.1 or 2.1.2 (check one)? ☐ Yes ☐ No ☐ Requires Licensing Review

UNIT RESTART SCREEN (ALL Issues – check one):

☐ None ☐ Initial System Fill/Vent ☐ Reload ☐ ORT 3 ☐ LTOP ☐ RCS Fill/Vent ☐ 140F ☒ 200F ☐ 350F ☐ 540F
☐ Criticality ☐ Steam in Secondary ☐ Grid Synchronization [redacted]

Screener Comments & Recommendations: __________

Screener Name: [redacted] **Signature:** [redacted] **Date/Time:** 4/26/01

CORRECTIVE ACTION ASSIGNMENT / MANAGEMENT REVIEW

Group Responsible for Issue Resolution: SOS

☐ **Operability Determination Required By Management (Return CR to Control Room)** **Date/Time:** ______ / ______

Regulatory Services Follow-up of Issue (NRC commitment) ☐ Yes ☒ No

Organizational Assessment Follow-up of Issue ☐ Yes ☒ No

Action Required: ☐ Root Cause ☐ Apparent Cause ☐ Routine Work/Plant Betterment (BCR) ☐ Document Only

Comments: Unit [redacted] U1R26 Restart (200F) – A[redacted] Review the Condition and Provide a resolution for the Issue presented.

EVALUATION OF CR 01-1517

BACKGROUND

The liner plate function throughout the containment is to form a leak tight boundary. It is not a pressure-retaining boundary. The liner is installed right against either reinforced or prestressed concrete members designed to withstand all the design loads as specified in the FSAR including pressure inside the containment due to a large LOCA.

During the design process of the containment a ¼" plate thickness was selected for two reasons: One, is to be used as a form for wet concrete during construction; Two, is to account for some corrosion during the lifetime of the plant instead of using expensive stainless steel plate.

The liner criteria as stated in the PBNP FSAR address limiting the liner strain level and not the stress level. This is due to the fact that the liner is not a pressure-retaining boundary. For a given liner strain the stress level is the same regardless of the thickness of the liner.

EVALUATION

Liner thickness measurements of unit 1 core drill hole CH-04, EL. 8'-0", taken as a result of IWE containment preservice inspection, indicate base metal reduction of more than 10% of nominal thickness of the ¼" liner. Measurements reported on NDE data sheet 01U1-114E004 varies from 0.252" in the general area to a minimum of 0.204".

NDE measurements of the same core hole CH-04 taken in 1988, when the core hole was bored, indicate a minimum liner thickness of 0.243" (CR 95-168). This is a reduction of 0.04" of the liner thickness during a 13 year period. Assuming a straight line reduction, the rate of reduction is equal to 0.003" per year. This is a very small rate considering the remaining life of the plant.

Under normal operating conditions, the basemat liner will not experience strain. Under LOCA conditions and during the reactor start up, the basemat liner is strained due to the increase in air temperature and liner temperature faster than the concrete temperature because of conductivity. When the concrete temperature reaches the same level as the liner then the strain in the liner will be released and the stress level becomes zero. Under pressure load due to LOCA the basemat liner will be strained to the same level as the concrete. Once the strain is known the stress in the liner can be calculated using the following formula:

$f_s = E \varepsilon$

Where: E = Modulus of Elasticity of steel.

ε = The strain of the liner plate

Since the liner thickness is not required to calculate the stress in the liner, it can be concluded that there is no minimum thickness required for the liner to function as a leak tight boundary and 0.204" liner thickness is acceptable for continued service.

1

CONCLUSION

The requirements of IWE-2420 of ASME Section XI are that the liner plate in question, the area containing degradation, should be inspected during the next two inspection periods. If the liner plate remains unchanged during the next two inspections, then no additional action is required. Since these additional inspections are already part of the IWE preservice inspection program, I recommend that this CR be closed with no further actions required.

Bechtel

9801 Washingtonian Boulevard
Gaithersburg, Maryland 20878 5356
(301) 417-3000

February 19, 1997

[redacted]
Nuclear Power Department
Wisconsin Electric Power Company
231 W. Michigan
Milwaukee, WI 53201

Subject: Point Beach Nuclear Plant Units 1 & 2
Bechtel Job 10447
RTS 97-01 Containment Liner Indentations/Containment Seismic Gap
NOPS 97-094 File: 0260, 0367

Dear Mr. [redacted]

This is a response to RTS 97-01 which requests an evaluation of several small indentations in the containment liner plate. Based on our evaluation, it is our conclusion that the indentations do not affect the integrity of the containment liner and no corrective action is required. The enclosed Engineering Judgment No. 97-10447-C001 is a summary of the evaluation of the condition

In addition, per your request, we have reviewed the containment seismic analysis results for relative seismic displacement between the containment and the containment internal structures. Based on our review, it is our conclusion that 3/4" is sufficient clearance between a component (e.g., raceways and supports) attached to either structure (containment or internal structures) and other structure to assure no contact during an SSE. The enclosed Engineering Judgment No. 97-10447-C002 is a summary of this evaluation.

This completes our response to RTS 97-01. If you have any questions, please contact Jag Jagannath at (301) 417-3397, or myself at (301) 417-3711.

Sincerely,

[redacted]

[redacted]
Project Engineer

[redacted]

Enclosures: 1. Engineering Judgment No. 97-10447-C-001
2. Engineering Judgment No. 97-10447-C-002

FEB 27 1997
PBNP

Bechtel Power Corporation

	ENGINEERING JUDGMENT / EXPEDITED ENGINEERING EVALUATION	No 97-10447-C-001 Sheet of 1 of 1

SUBJECT.

☐ Calculation ☐ Study ☐ Modification ☒ Other, Describe Engineering Evaluation

BASE/INITIATING DOCUMENT NO

REQUEST FOR TECHNICAL SERVICES (RTS) 97-01
CONDITION REPORT 97-008

DESCRIPTION OF CHANGE/SUBJECT OF INQUIRY

RTS 97-01 requests engineering to evaluate six (6) indentations (dings) in the Point Beach Unit 2 containment liner plate. The indentations are shown on the attached field sketch.
The indentations were only recently noticed while performing modifications to the "A" fan platform, however, WEPCO engineering indicates that the indentations have been there since the plant construction. It is believed that they were caused by the threaded end of connection bolts for the platform gouging the liner plate as they were tightened.

ENGINEERING JUDGMENT/EVALUATION (including cumulative impact of all known changes):

The indentations (dings) do not affect the integrity of the liner, and no repair is required.

JUSTIFICATION AND/OR RESPONSE:

Effect of the Indentation On Liner Plate Leaktightness

The maximum depths of the 6 indentations range from approx. 1/32" to 1/16". The containment liner plate is ¼" thick A-442 steel, therefore, there is at least 3/16" thickness of liner plate intact. The containment leak tight barrier is not affected by the indentations.

Effect of the Indentation On The Ability of the Liner Plate To Resist Design Basis Loading

The containment liner system is used as an internal form for the containment concrete during construction, and the plate thickness is determined based on the concrete placement loads. During plant operation, the liner is considered a non-structural element. Therefore, it serves a structural purpose only during construction and is not assumed to transfer loads required for equilibrium during plant operation. Because the liner plate system is assumed to perform no structural function after the concrete is hardened, it becomes more appropriate to evaluate it in terms of strain rather than stress. Significant sources of the liner plate strains include enforced displacements due to concrete shrinkage, creep, and prestressing, as well as, strains due to normal operating and accident themperatures and pressures. Since the small indentations do not affect liner plate strains, they do not affect the ability of the liner resist normal and design basis loads.

PREPARED BY:	[redacted]	Date	2/19/97
CHECKED BY:	[redacted]	Date	2/19/97
EGS	[redacted]	Date	2/19/97
PROJECT ENGINEER.	[redacted]	Date	2/19/97
COPY TO FILE NO:	0260, 0367 (RTS 97-01)		

ENCLOSURE 2

NMC RESPONSES TO CONFIRMATORY ITEMS IN THE DRAFT SAFETY EVALUATION REPORT (SER) REGARDING POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2 LICENSE RENEWAL APPLICATION

The following information is provided in response to the Nuclear Regulatory Commission (NRC) staff's draft SER with open items regarding the Point Beach Nuclear Plant (PBNP) License Renewal Application (LRA).

The NRC staff's confirmatory items are restated below with the Nuclear Management Company (NMC) response following.

<u>NRC Confirmatory Item CI 2.1-1</u> (Section 2.1.2.1.2 - Application of the Scoping Criteria in 10 CFR 54.4(a)):

In RAI 2.1-1, dated November 16, 2004, the staff requested additional information regarding the scoping methodology associated with the 10 CFR 54.4(a)(2) evaluation. The staff requested the applicant to adequately define short term exposure duration as it relates to the evaluation of low and moderate energy piping failures that could affect safety related electrical equipment. Since this equipment may not be environmentally qualified, it could fail due to 10 CFR 54.4(a)(2) piping failures

In its response, dated January 31, 2005, the applicant stated that for the purpose of license renewal, the term "exposure duration" will be removed from LRA Section 2.1.2.1.2 and it will provide a technical justification as to why the safety-related SSCs are capable of withstanding the effects of spray and leakage. The applicant also stated that it will include a technical justification in the LRA annual update under the section "Components Qualified/Designed for Environment".

During a meeting on February 15, 2005, the staff indicated and the applicant agreed, that this response required further clarification. In its response, a clarification letter dated March 15, 2005, the applicant committed to provide details of the 10 CFR 54.4(a)(2) scoping methodology changes, including specific exceptions, and how these will impact the LRA. The staff agreed with the applicant's proposed methodology changes. However, the applicant committed to provide detailed information with regard to these changes by the end of April 2005. This was identified as confirmatory item (CI) 2.1-1.

NMC Response:

The information requested in this confirmatory item, regarding the details of the 10 CFR 54.4(a)(2) scoping methodology changes, including specific exceptions and the impact on the LRA, was provided by letter from NMC to NRC dated April 29, 2005 (NRC 2005-0051).

NRC Confirmatory Item CI 2.1-2 (Section 2.1.3.1.1 - Application of the Scoping Criteria in 10 CFR 54.4(a)):

In RAI 2.1-2, dated November 16, 2004, the staff requested additional information regarding the scoping methodology associated with the 10 CFR 54.4(a)(2) evaluation. The staff requested the applicant to define first equivalent anchor as it relates to the evaluation of nonsafety-related piping directly connected to safety-related piping. The staff also requested the applicant to describe the methodology of its application. Additionally, in cases where plant equipment credited with providing support to nonsafety-related piping may be equivalent to an associated piping anchor as described in NUREG-1800, the staff requested the applicant to provide justification for not including this plant equipment within the scope of license renewal.

In its response, dated January 31, 2005, the applicant stated that PBNP has included all the connected nonsafety-related piping and supports, up to and including the first equivalent anchor beyond the safety/nonsafety interface, within the scope of license renewal. The applicant also stated that nonsafety-related pipe supports will be managed in a commodity "spaces" approach wherein all supports in the areas of concern are included within the scope of license renewal. The directly connected nonsafety-related piping will be age-managed using the same programs that manage the safety-related piping. This process conforms to the requirements for the nonsafety-related SSCs connected to safety-related SSCs pursuant to 10 CFR 54.4(a)(2) and the guidance of draft ISG-09. This was identified as confirmatory item (CI) 2.1-2.

NMC Response:

The information requested in this confirmatory item, regarding the definition of first equivalent anchor, was provided in response to NRC Question RAI 2.1.2 by letter from NMC to NRC dated January 31, 2005 (NRC 2005-0001).

NRC Confirmatory Item CI 2.1-3 (Section 2.1.2.1.2 - Flow-Accelerated Corrosion Effect on Piping Section Scoping in 10 CFR 54.4(a)(2)):

In RAI 2.1-3, dated November 16, 2004, the staff requested additional information regarding the scoping methodology associated with the 10 CFR 54.4(a)(2) evaluation. The staff requested the applicant to describe how the falling of piping sections is not considered credible and why the piping section itself would not be within the scope of license renewal pursuant to 10 CFR 54.4(a)(2) due to physical impact hazard. The staff also requested the applicant to describe how the management of flow-accelerated corrosion (FAC) relates to the scoping and screening of 10 CFR 54.4(a)(2) Seismic II/I piping systems that could cause these types of failures.

In its response, dated January 31, 2005, the applicant stated that for the purpose of license renewal, the nonsafety-related pipe segments, for the Criterion 2 scoping, have essentially three potential modes: (1) for nonsafety-related low or moderate energy piping, managing of the nonsafety-related supports will ensure that these supports remain intact and will not fall on safety-related components, (2) for nonsafety-related high energy piping segments, FAC failure for components in proximity of safety-related components would be considered within the scope of license renewal as long as failure is considered credible, and (3) for nonsafety-related piping sections that could have spray, leakage, or harsh environment effects on vulnerable safety-related equipment, are considered within the scope of license renewal.

During a meeting on February 15, 2005, the staff indicated and the applicant agreed, that this response required further clarification. In its response, a clarification letter dated March 15, 2005, the applicant committed to remove from the response the phrase "as long as a FAC failure is considered credible." This was identified as confirmatory item (CI) 2.1-3.

<u>NMC Response</u>:

The information requested in this confirmatory item, regarding the removal of the phrase "as long as a FAC failure is considered credible" from the description of the 10 CFR 54.4(a)(2) scoping methodology for non-safety related pipe segments, was provided in NMC Clarification to RAI 2.1-3 by letter from NMC to NRC dated March 15, 2005 (NRC 2005-0026). The results of the revised 10 CFR 54.4(a)(2) scoping methodology, regarding non-safety related piping whose failure due to flow-accelerated corrosion could affect safety related components, was provided by letter from NMC to NRC dated April 29, 2005 (NRC 2005-0051).

<u>NRC Confirmatory Item CI 2.4-2</u> (Section 2.4.8 - Yard Structures):

LRA Section 2.4 does not appear to contain information about tanks and their foundations. In RAI 2.4-2, dated January 27, 2005, the staff requested the applicant to provide a list of all tanks and their foundations for each unit. Additionally, the staff requested the applicant to: (1) identify the tanks and their foundations that are in-scope and define their intended functions, (2) identify the tanks and their foundations that are not in-scope and the basis for their exclusion, and (3) specify where the AMR for each in-scope tank and tank foundation is located in the LRA.

In its response, dated February 25, 2005, the applicant stated that tanks are associated with the system in which they reside. They are addressed and scoped in the mechanical section of the LRA, Section 2.3. The tables in LRA Section 2.3 have a component group, "Tanks." The license renewal drawings for the systems are listed

ENCLOSURE 2

NMC RESPONSES TO CONFIRMATORY ITEMS IN THE DRAFT SAFETY EVALUATION REPORT (SER) REGARDING POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2 LICENSE RENEWAL APPLICATION

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The information requested in this confirmatory item, regarding the details of the 10 CFR 54.4(a)(2) scoping methodology changes, including specific exceptions and the impact on the LRA, was provided by letter from NMC to NRC dated April 29, 2005 (NRC 2005-0051).

NRC Confirmatory Item CI 2.1-2 (Section 2.1.3.1.1 - Application of the Scoping Criteria in 10 CFR 54.4(a)):

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In its response, dated January 31, 2005, the applicant stated that PBNP has included all the connected nonsafety-related piping and supports, up to and including the first equivalent anchor beyond the safety/nonsafety interface, within the scope of license renewal. The applicant also stated that nonsafety-related pipe supports will be managed in a commodity "spaces" approach wherein all supports in the areas of concern are included within the scope of license renewal. The directly connected nonsafety-related piping will be age-managed using the same programs that manage the safety-related piping. This process conforms to the requirements for the nonsafety-related SSCs connected to safety-related SSCs pursuant to 10 CFR 54.4(a)(2) and the guidance of draft ISG-09. This was identified as confirmatory item (CI) 2.1-2.

NMC Response:

The information requested in this confirmatory item, regarding the definition of first equivalent anchor, was provided in response to NRC Question RAI 2.1.2 by letter from NMC to NRC dated January 31, 2005 (NRC 2005-0001).

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In RAI 2.1-3, dated November 16, 2004, the staff requested additional information regarding the scoping methodology associated with the 10 CFR 54.4(a)(2) evaluation. The staff requested the applicant to describe how the falling of piping sections is not considered credible and why the piping section itself would not be within the scope of license renewal pursuant to 10 CFR 54.4(a)(2) due to physical impact hazard. The staff also requested the applicant to describe how the management of flow-accelerated corrosion (FAC) relates to the scoping and screening of 10 CFR 54.4(a)(2) Seismic II/I piping systems that could cause these types of failures.

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<u>NMC Response:</u>

The information requested in this confirmatory item, regarding the removal of the phrase "as long as a FAC failure is considered credible" from the description of the 10 CFR 54.4(a)(2) scoping methodology for non-safety related pipe segments, was provided in NMC Clarification to RAI 2.1-3 by letter from NMC to NRC dated March 15, 2005 (NRC 2005-0026). The results of the revised 10 CFR 54.4(a)(2) scoping methodology, regarding non-safety related piping whose failure due to flow-accelerated corrosion could affect safety related components, was provided by letter from NMC to NRC dated April 29, 2005 (NRC 2005-0051).

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LRA Section 2.4 does not appear to contain information about tanks and their foundations. In RAI 2.4-2, dated January 27, 2005, the staff requested the applicant to provide a list of all tanks and their foundations for each unit. Additionally, the staff requested the applicant to: (1) identify the tanks and their foundations that are in-scope and define their intended functions, (2) identify the tanks and their foundations that are not in-scope and the basis for their exclusion, and (3) specify where the AMR for each in-scope tank and tank foundation is located in the LRA.

In its response, dated February 25, 2005, the applicant stated that tanks are associated with the system in which they reside. They are addressed and scoped in the mechanical section of the LRA, Section 2.3. The tables in LRA Section 2.3 have a component group, "Tanks." The license renewal drawings for the systems are listed and tanks that are in-scope are highlighted on the drawings. Tank foundations are scoped in LRA Section 2.4 and are typically constructed of concrete or steel. Tanks foundations and intended functions are typically presented in LRA Sections 2.4.8 and 2.4.10, or individual section for the building. Tank and tank foundation AMR information is contained in the corresponding LRA Sections 3.1 through 3.5.

Based on its review, the staff finds the applicant's response to RAI 2.4-2 acceptable in that tanks are addressed and scoped in the mechanical section, LRA Section 2.3. However, the staff finds unacceptable the omission of tank foundations from LRA Section 2.4. The applicant should identify the tank foundations that are within the scope of license renewal. This was identified as confirmatory item (CI) 2.4-2.

<u>NMC Response</u>:

Individual tanks that are within the scope of License Renewal are included in the table below.

Unit	Equip ID	Description
PB0	SFP	SPENT FUEL POOL STRUCTURE
PB0	SI-00850A/B HYDROLIC RESERVOIR	SUMP VALVE HYDRAULIC OPERATOR GENERIC ASSET FOR OIL RESERVOIRS.
PB1	T-002	PRESSURIZER RELIEF TANK
PB2	T-002	PRESSURIZER RELIEF TANK
PB1	T-005	CHEMICAL MIXING TANK
PB2	T-005	CHEMICAL MIXING TANK
PB1	T-006A	BORIC ACID TANK W/HEATER
PB0	T-006B	BORIC ACID TANK W/HEATER
PB2	T-006C	BORIC ACID TANK W/HEATER
PB0	T-007	BORIC ACID BATCHING TANK W/AGITATOR
PB0	T-008A	CVCS HOLDUP TANK
PB0	T-009A	BORIC ACID EVAPORATOR RESERVOIR
PB0	T-009B	BORIC ACID EVAPORATOR RESERVOIR
PB0	T-010A	MONITOR TANK
PB0	T-010B	MONITOR TANK
PB0	T-010C	MONITOR TANK
PB0	T-010D	MONITOR TANK
PB1	T-012	COMPONENT COOLING SURGE TANK
PB2	T-012	COMPONENT COOLING SURGE TANK
PB1	T-013	REFUELING WATER STORAGE TANK W/6 IMMERSION HTRS
PB2	T-013	REFUELING WATER STORAGE TANK W/6 IMMERSION HTRS
PB1	T-013-BOTTOM	SUBCOMPONENT - REFUELING WATER STORAGE TANK BOTTOM
PB2	T-013-BOTTOM	SUBCOMPONENT - REFUELING WATER STORAGE TANK BOTTOM
PB0	T-019	WASTE HOLDUP TANK
PB0	T-024A	CONDENSATE STORAGE TANK
PB0	T-024B	CONDENSATE STORAGE TANK
PB1	T-026	BLOWDOWN TANK
PB2	T-026	BLOWDOWN TANK
PB0	T-030	P-35B DIESEL DRIVEN FIRE PUMP FUEL OIL DAY TANK

Unit	Equip ID	Description
PB0	T-031A	G-01 DIESEL GENERATOR DAY TANK
PB0	T-031B	G-02 DIESEL GENERATOR DAY TANK
PB0	T-032A	FUEL OIL STORAGE TANK
PB0	T-032B	FUEL OIL STORAGE TANK
PB1	T-034A	SAFETY INJECTION ACCUMULATOR
PB2	T-034A	SAFETY INJECTION ACCUMULATOR
PB1	T-034A-CLAD	SUBCOMPONENT - SAFETY INJECTION ACCUMULATOR
PB2	T-034A-CLAD	SUBCOMPONENT - SAFETY INJECTION ACCUMULATOR
PB1	T-034B	SAFETY INJECTION ACCUMULATOR
PB2	T-034B	SAFETY INJECTION ACCUMULATOR
PB2	T-034B-CLAD	SUBCOMPONENT - SAFETY INJECTION ACCUMULATOR
PB1	T-034B-CLAD	SUBCOMPONENT - SAFETY INJECTION ACCUMULATOR
PB0	T-037A	WASTE CONDENSATE TANK
PB0	T-037B	WASTE CONDENSATE TANK
PB1	T-038	SPRAY ADDITIVE TANK
PB2	T-038	SPRAY ADDITIVE TANK
PB2	T-038-CLAD	SUBCOMPONENT - SPRAY ADDITIVE TANK - INTERNAL CLADDING
PB1	T-038-CLAD	SUBCOMPONENT - SPRAY ADDITIVE TANK - INTERNAL CLADDING
PB0	T-046	G-05 GT GEN W-503 LO VAPOR EXTRACTOR VENT LINE TANK
PB0	T-055	HX-25 WASTE EVAPORATOR DISTILLATE TANK
PB1	T-058A	P-2A CHARGING PUMP SUCTION PRESSURE STABILIZER
PB2	T-058A	P-2A CHARGING PUMP SUCTION PRESSURE STABILIZER
PB1	T-058B	P-2B CHARGING PUMP SUCTION PRESSURE STABILIZER
PB2	T-058B	P-2B CHARGING PUMP SUCTION PRESSURE STABILIZER
PB1	T-058C	P-2C CHARGING PUMP SUCTION PRESSURE STABILIZER
PB2	T-058C	P-2C CHARGING PUMP SUCTION PRESSURE STABILIZER
PB0	T-060A	G-01 EDG STARTING AIR RECEIVER (RIGHT BANK)
PB0	T-060B	G-01 EDG STARTING AIR RECEIVER (RIGHT BANK)
PB0	T-060C	G-01 EDG STARTING AIR RECEIVER (RIGHT BANK)
PB0	T-060D	G-01 EDG STARTING AIR RECEIVER (LEFT BANK)
PB0	T-060E	G-01 EDG STARTING AIR RECEIVER (LEFT BANK)
PB0	T-060F	G-01 EDG STARTING AIR RECEIVER (LEFT BANK)
PB0	T-061A	G-02 EDG STARTING AIR RECEIVER (RIGHT BANK)
PB0	T-061B	G-02 EDG STARTING AIR RECEIVER (RIGHT BANK)
PB0	T-061C	G-02 EDG STARTING AIR RECEIVER (RIGHT BANK)
PB0	T-061D	G-02 EDG STARTING AIR RECEIVER (LEFT BANK)
PB0	T-061E	G-02 EDG STARTING AIR RECEIVER (LEFT BANK)
PB0	T-061F	G-02 EDG STARTING AIR RECEIVER (LEFT BANK)
PB0	T-066	HX-25 WASTE EVAPORATOR FEED TANK/HEATER
PB0	T-067	WASTE EVAPORATOR CONCENTRATOR
PB0	T-068	HX-25 WASTE EVAPORATOR HOT WATER EXPANSION TANK
PB0	T-069A	HX-8A U1 BA EVAPORATOR FEED TANK W/IMMERSION HEATER
PB0	T-069B	HX-8B U2 BA EVAPORATOR FEED TANK W/IMMERSION HEATER
PB1	T-070A	P-2A CHARGING PUMP DISCHARGE ACCUMULATOR
PB2	T-070A	P-2A CHARGING PUMP DISCHARGE ACCUMULATOR
PB1	T-070B	P-2B CHARGING PUMP DISCHARGE ACCUMULATOR
PB2	T-070B	P-2B CHARGING PUMP DISCHARGE ACCUMULATOR

Unit	Equip ID	Description
PB1	T-070C	P-2C CHARGING PUMP DISCHARGE ACCUMULATOR
PB2	T-070C	P-2C CHARGING PUMP DISCHARGE ACCUMULATOR
PB0	T-072	EMERGENCY FUEL OIL STORAGE TANK
PB0	T-073	ACCUMULATOR TANK
PB0	T-075	HX-25 WASTE EVAPORATOR REAGENT TANK
PB0	T-078	HX-38A1-A4 CSR AC UNIT CHILLED WATER EXPANSION TANK
PB0	T-079	HX-38B1-B4 CR AC UNIT CHILLED WATER EXPANSION TANK
PB0	T-102	BLOWDOWN EVAPORATOR SURGE TANK
PB0	T-104A	WASTE DISTILLATE TANK
PB0	T-104B	WASTE DISTILLATE TANK
PB1	T-106	SGBD SAMPLE SPARGING AND CHEMICAL ADDITION TANK
PB2	T-106	SGBD SAMPLE SPARGING AND CHEMICAL ADDITION TANK
PB0	T-107	CONDENSATE RECEIVER/RADWASTE CONDENSATE
PB0	T-108A	WASTE CONDENSATE POLISHING DEMINERALIZER
PB0	T-108B	WASTE CONDENSATE POLISHING DEMINERALIZER
PB0	T-141	P-88A/B COND RETURN PUMP COND RECEIVER TANK
PB0	T-142	P-89A/B COND RETURN PUMP COND RECEIVER TANK
PB0	T-143	P-90A/B COND RETURN PUMP COND RECEIVER TANK
PB0	T-144	P-103A/B CONDENSATE RETURN PUMP COND RCVR TANK
PB0	T-148	P-102A/B CONDENSATE RETURN PUMP COND RCVR TANK
PB0	T-152A	AIR BANK A RECEIVER
PB0	T-152B	AIR BANK A RECEIVER
PB0	T-152C	AIR BANK A RECEIVER
PB0	T-152D	AIR BANK A RECEIVER
PB0	T-152E	AIR BANK A RECEIVER
PB0	T-153A	AIR BANK B RECEIVER
PB0	T-153B	AIR BANK B RECEIVER
PB0	T-153C	AIR BANK B RECEIVER
PB0	T-153D	AIR BANK B RECEIVER
PB0	T-153E	AIR BANK B RECEIVER
PB0	T-161A	HX-140 BDE CALGON MIXING TANK
PB0	T-161B	HX-140 BDE CALGON MEASURING CYLINDER
PB0	T-161C	HX-140 BDE CALGON DRUM
PB0	T-169A	G-01 EDG COOLANT EXPANSION TANK
PB0	T-169B	G-02 EDG COOLANT EXPANSION TANK
PB0	T-170A	G-03 EDG STARTING AIR RECEIVER
PB0	T-170B	G-03 EDG STARTING AIR RECEIVER
PB0	T-170C	G-03 EDG STARTING AIR RECEIVER
PB0	T-170D	G-03 EDG STARTING AIR RECEIVER
PB0	T-171A	G-04 EDG STARTING AIR RECEIVER
PB0	T-171B	G-04 EDG STARTING AIR RECEIVER
PB0	T-171C	G-04 EDG STARTING AIR RECEIVER
PB0	T-171D	G-04 EDG STARTING AIR RECEIVER
PB0	T-175A	G-01/G-02 EDG FUEL OIL STORAGE TANK
PB0	T-175B	G-03/G-04 EDG FUEL OIL STORAGE TANK
PB0	T-176A	G-03 EDG FUEL OIL DAY TANK
PB0	T-176B	G-04 EDG FUEL OIL DAY TANK

Unit	Equip ID	Description
PB0	T-177A	G-03 EDG COOLANT EXPANSION TANK
PB0	T-177B	G-04 EDG COOLANT EXPANSION TANK
PB1	T-188	VNPSE-3212 U1C PURGE EXH FAN SUCT BOOT SEAL ACCUMULATOR
PB2	T-188	VNPSE-3212 U2C PURGE EXH FAN SUCT BOOT SEAL ACCUMULATOR
PB1	T-189	VNPSE-3213 U1C PURGE EXH FAN SUCT BOOT SEAL ACCUMULATOR
PB2	T-189	VNPSE-3213 U2C PURGE EXH FAN SUCT BOOT SEAL ACCUMULATOR
PB1	T-190	VNPSE-3244 U1C PURGE SUP FAN DISCH BOOT SEAL ACCUMULATOR
PB2	T-190	VNPSE-3244 U2C PURGE SUP FAN DISCH BOOT SEAL ACCUMULATOR
PB1	T-191	VNPSE-3245 U1C PURGE SUP FAN DISCH BOOT SEAL ACCUMULATOR
PB2	T-191	VNPSE-3245 U2C PURGE SUP FAN DISCH BOOT SEAL ACCUMULATOR
PB1	T-212	1P-29 AFP MINI RECIRC IA 1AF-4002 BACKUP ACCUMULATOR
PB2	T-212	2P-29 AFP MINI RECIRC IA 2AF-4002 BACKUP ACCUMULATOR
PB0	T-213	K-46 BACKUP AIR COMPRESSOR AIR RECEIVER
PB0	T-500	G-05 GT GENERATOR IA COMPRESSOR RECEIVER
PB0	T-501	G-05 GT GENERATOR ATOMIZING AIR COMPRESSOR RECEIVER
PB0	T-502	G-05 GT GENERATOR GLYCOL EXPANSION TANK
PB0	T-503	P-503 GT GEN FUEL OIL PUMP DISCHARGE ACCUMULATOR
PB0	T-504	G-500 GT GEN STARTING DIESEL ENGINE FUEL OIL TANK
PB0	T-505	G-501 GT GEN AUX POWER DIESEL ENGINE FUEL OIL TANK
PB0	T-7 JACKET HEATER	JACKET STEAM HEAT SECTION OF T-7 BORIC ACID BATCH TANK
PB0	T-710	BA WASTE EVAP VACUUM SYSTEM WATER SEPARATOR
PB0	U-03A	BORIC ACID EVAPORATOR CONDENSATE DEMINERALIZER
PB0	U-03B	BORIC ACID EVAPORATOR CONDENSATE DEMINERALIZER
PB0	U-03C	BORIC ACID EVAPORATOR CONDENSATE DEMINERALIZER
PB1	U-04241A	HX-1A SG CONDUCTIVITY CATION SAMPLE COLUMN
PB2	U-04241A	HX-1A SG CONDUCTIVITY CATION SAMPLE COLUMN
PB1	U-04241B	HX-1B SG CONDUCTIVITY CATION SAMPLE COLUMN
PB2	U-04241B	HX-1B SG CONDUCTIVITY CATION SAMPLE COLUMN
PB0	Z-058A	WASTE GAS MOISTURE SEPARATOR
PB0	Z-058B	WASTE GAS MOISTURE SEPARATOR
PB0	Z-288	Z-46 GAS ANALYZER MOISTURE SEPARATOR
PB0	Z-402	P-13 SFP SKIMMER PUMP AIR SEPARATOR
PB0	Z-403	P-13 SFP SKIMMER PUMP PRIMING CHAMBER

<u>NRC Confirmatory Item CI B2.1.4-3</u> (Section 3.0.3.2.4 - Bolting Integrity Program):

In RAI B2.1.4-3, dated February 7, 2005, the staff requested the applicant to provide data that demonstrate that the bolting, loaded with the maximum shear stress, would not be susceptible to SCC. Additionally, the staff requested the applicant to identify the inspection history for its bolts that demonstrate that they are not susceptible to SCC.

In its response, dated March 4, 2005, the applicant stated, in part, that the Boric Acid Program takes a critical look at bolting. Whenever boric acid is found, the requirement is to look at the flow path of where the boric acid has traveled. If boric acid is found on bolting, the boric acid will be removed and a visual examination performed on the fasteners to determine if any degradation has occurred. NMC will follow plant procedures for repair or replacement if the evaluation determines the bolting is not acceptable.

The inspection history results are reported in the applicant's response to RAI B2.1.4-3. Since 1991, reactor coolant pump supports and SG supports have been inspected on numerous occasions. No recordable indications have been observed. The Region III staff, on its AMR/AMP onsite inspection during the weeks of March 7 and 21, 2005, will confirm that there were no failure of high strength bolts. This was identified as confirmatory item (CI) B2.1.4-3.

NMC Response:

The information requested in this confirmatory item, regarding confirmation during the March 2005 NRC Region III License Renewal Inspection that there were no failures of high strength bolts, was provided to the NRC as documented in NRC Inspection Report 2005-005 dated May 2, 2005.

NRC Confirmatory Item CI B2.1.11-1 (Section 3.0.3.2.11 - Flow-Accelerated Corrosion Program):

During the audit, the staff noted that for the "acceptance criteria" program element, it is unclear how the applicant calculates the minimum permitted wall thickness and how it is used in its analysis for flow-accelerated corrosion. In RAI B2.1.11-1, dated March 30, 2005, the staff requested the applicant to clarify its wall thickness calculation and its uses.

The staff's concern was referred to the Region III staff, which performed its AMR/AMP onsite inspection during the weeks of March 7 and 21, 2005. The applicant clarified its methodology. The applicant stated that the minimum wall calculations are performed using the design pressure, which is greater than the operating pressure and demonstrates that the actual measured wall thickness is greater than the minimum thickness required by the maximum hoop stress. If degradation is detected such that the wall thickness is less than or equal to 87.5 percent of nominal wall thickness for safety-related piping or 60 percent of nominal wall thickness for nonsafety-related piping, additional examinations will be performed in adjacent areas to bound the thinning and assure that the actual minimum wall is measured. In addition, the applicant will provide its justification and confirmation that the minimum wall thickness will be maintain for the period of extended operation. This was identified as confirmatory item (CI) B2.1.11-1.

NMC Response:

A detailed review of the Flow Accelerated Corrosion Program (LRA Section B2.1.11) was performed during the March 2005 NRC Region III License Renewal Inspection. As a result of that review and discussions between the NRC Region III inspection team, the NRC License Renewal Branch, and NRC Division of Engineering personnel, a clarification to the information provided under the elements of "Monitoring and Trending" and "Acceptance Criteria" in the Flow Accelerated Corrosion Program was provided by letter from NMC to NRC dated April 8, 2005 (NRC 2005-0037). Based upon discussions with the NRC staff on May 3, 2005, a revision to the April 8, 2005, letter was identified as being needed to clarify the intent of the sample expansion criterion under the element of "Monitoring and Trending" in the Flow Accelerated Corrosion Program. This revision was provided in the response to NRC Question RAI B2.1.11-1 by letter dated June 9, 2005, (NRC 2005-0044). Therefore, the information requested in this confirmatory item, regarding the minimum permitted wall thickness and how it is used in its analysis for flow accelerated corrosion, was provided by letters from NMC to NRC dated April 8, 2005, (NRC 2005-0037) and June 9, 2005, (NRC 2005-0044).

<u>NRC Confirmatory Item CI 3.1.1-1</u> (Section 3.1.2.1.1 - Loss of Fracture Toughness Due to Thermal Aging Embrittlement):

The staff finds that the use of leak-before-break evaluation method is not equivalent to a flaw tolerance methodology; it assumes through-wall leakage and therefore does not assure the safety function of pressure boundary integrity. In RAI 3.1.1-1, dated March 30, 2005, the staff requested the applicant to clarify how it manages the aging effect of loss of fracture toughness due to thermal aging embrittlement for CASS primary loop elbows. During a telephone conference, the applicant agreed to revise its position and perform flaw tolerance evaluations. This was identified as confirmatory item (CI) 3.1.1-1.

<u>NMC Response:</u>

The information requested in this confirmatory item, regarding the management of the aging effect loss of fracture toughness due to thermal aging embrittlement for cast austenitic stainless steel primary loop elbows, was provided in response to NRC Question RAI 3.1.1-1 by letter from NMC to NRC dated June 9, 2005 (NRC 2005-0044).

<u>NRC Confirmatory Item CI 3.1.1-2</u> (Section 3.1.2.2.10 - Loss of Section Thickness Due to Erosion):

In RAI 3.1.1-2, dated March 30, 2005, the staff requested the applicant to justify why the steam generator feedrings and associated J-tubes are outside the scope of license renewal. During a telephone conference, the applicant agreed to add the steam generator feedrings and J-tubes to the scope of license renewal and manage the associated aging effects. This was identified as confirmatory item (CI) 3.1.1-2.

NMC Response:

The information requested in this confirmatory item, regarding whether the steam generator feedrings and associated J-tubes are within the scope of license renewal, was provided in response to NRC Question RAI 3.1.1-2 by letter from NMC to NRC dated June 9, 2005 (NRC 2005-0044).

NRC Confirmatory Item CI 3.5-12 (Section 3.5.2.2.1 - PWR Containments - Cracking Due to Cyclic Loading and Stress Corrosion Cracking (SCC)):

In LRA Section 3.5.2.2.1.7, the applicant stated that SCC is not an applicable aging mechanism for penetration sleeves, bellows, and dissimilar metal welds. Therefore, the applicant did not address cracking due to cyclic loading. In RAI 3.5-12, dated March 30, 2005, the staff requested the applicant to address the difference between its position and the GALL Report recommendation of enhanced inspection methods. The staff noted that the TLAA in LRA Section 4.3.11 does not detect and manage cracking due to cyclic loading. The applicant was requested to provide further clarification for crediting this specific line item to manage cracking due to cyclic loading.

During a telephone conference, the applicant indicated that this is a TLAA and will provide information to confirm that this is adequately addressed in LRA Section 4.3.11. The staff agreed with the applicant's statement. This was identified as confirmatory item (CI) 3.5-12.

NMC Response:

The information requested in this confirmatory item, regarding the management of the aging effects cracking due to cyclic loading and stress corrosion cracking of containment penetration sleeves, bellows, and dissimilar metal welds, was provided in response to NRC Question RAI 3.5-12 by letter from NMC to NRC dated June 9, 2005 (NRC 2005-0044).

NRC Confirmatory Item CI 3.5-13 (Section 3.5.2.2.1 - PWR Containments - Aggressive chemical attack):

In LRA Section 3.5.2.2.1.1, the applicant stated that concrete degradation in air due to aggressive rainwater is insignificant and that the below-grade/lake water environment is nonaggressive. In RAI 3.5-13, dated March 30, 2005, the staff requested the applicant to provide sufficient data to support this statement.

Furthermore, during the review, the staff was unable to identify how the LRA addresses the items described in ISG-03. The staff requested the applicant to provide detailed information with regard to how its AMRs address all the items described in ISG-03.

During a telephone conference, the applicant described how it will satisfy the ISG-03 criteria and agreed to provide its most recent data with respect to the below-grade/lake water. The applicant committed to provide a formal response, including a table detailing how it satisfies all the items described in ISG-03. This was identified as confirmatory item (CI) 3.5-13.

NMC Response:

The information requested in this confirmatory item, regarding aggressive chemical attack of containment concrete and ISG-03, was provided in response to NRC Question RAI 3.5-13 by letter from NMC to NRC dated June 9, 2005 (NRC 2005-0044).

NRC Confirmatory Item CI 3.5-14 (Section 3.5.2.2.3 - Component Supports - Aging of Supports Not Covered by the Structures Monitoring Program):

In LRA Table 3.5.1, Item 3.5.1-33, the applicant stated that the Bolting Integrity Program includes the use of Inservice Inspection to evaluate and monitor crack initiation and growth due to SCC, if present, in high strength low-alloy steel bolts used in NSSS component supports. In LRA Tables 3.5.2-1 through 3.5.2-14, the applicant does not address Group B1.1, high strength low-alloy bolts. In LRA Section B2.1.4, the applicant indicated that high strength component support bolting is used in pinned connections associated with steam, reactor coolant pumps and reactor vessel supports and is loaded only in shear with no preload stress.

In RAI 3.5-14, dated March 31, 2005, the staff requested the applicant to identify how aging will be managed for the Group B1.1, high strength low-alloy bolts. During a telephone conference, the applicant stated that this RAI is similar to one previously issued for the Bolting Integrity Program, RAI B2.1.4-3. The staff reviewed the applicant's response to this RAI and found it acceptable. The applicant proposed how to manage aging and credited the Boric Corrosion Program and it plant procedures. The applicant also acknowledged that PBNP have some torqued high-strength bolts. The applicant will supplement its response to reflect this statement. This was identified as confirmatory item (CI) 3.5-14.

NMC Response:

The information requested in this confirmatory item, regarding crack initiation and growth due to stress corrosion cracking in high strength low-alloy bolts used in NSSS component supports, was provided in response to NRC Question RAI 3.5-14 by letter from NMC to NRC dated April 29, 2005 (NRC 2005-0043).

NRC Confirmatory Item CI 4.6.1-1.1 (Section 4.6.1 - Spent Fuel Pool Storage Rack Boraflex):

The surveillance frequency of once every 5 years for blackness testing was approved in an NRC letter dated February 21, 1990. Based on industry operating experience indicating the varying degree to which the Boraflex panels degrade, the staff requested a justification for continuing the 5-year frequency for areal density testing into the period of extended operation. In RAI 4.6.1-1, dated March 29, 2005, the staff requested the applicant provide the most recent blackness test and SFP silica level measurements, and use this data to demonstrate that the current rate of degradation will not exceed the acceptance criteria.

During conversations with the staff, the applicant committed to enhance the Boraflex Monitoring Program, and agreed to provide the requested data to the Region III staff at their onsite inspection during the weeks of March 7 and 21, 2005. The applicant's data and the Boraflex Monitoring Program enhancements are expected to ensure that the neutron absorbing material will continue to perform its intended function during the period of extended operation. This was identified as confirmatory item (CI) 4.6.1-1.1.

NMC Response:

The information requested in this confirmatory item, regarding the Boraflex Monitoring Program (LRA Section B2.1.5), was provided in response to NRC Questions RAI 4.6.1-1, RAI 4.6.1-2, and RAI 4.6.1-3 by letter from NMC to NRC dated April 1, 2005 (NRC 2005-0038). In addition, a detailed review of the Boraflex Monitoring Program was performed during the March 2005 NRC Region III License Renewal Inspection. The results of this review are documented in NRC Inspection Report 2005-005 dated May 2, 2005.

NRC Confirmatory Item CI 4.6.1-1.2 (Section 4.6.1 - Spent Fuel Pool Storage Rack Boraflex):

Additionally, in RAI 4.6.1-1, dated March 29, 2005, the staff requested the applicant to provide justification for the 5-year frequency for areal density testing. During conversations with the staff, the applicant committed to perform areal density and blackness tests once every 2 years during the period of extended operation. The applicant will revise its response to reflect this statement. This was identified as confirmatory item (CI) 4.6.1-1.2.

NMC Response:

The information requested in this confirmatory item, regarding the Boraflex Monitoring Program (LRA Section B2.1.5), was provided in response to NRC Questions RAI 4.6.1 1, RAI 4.6.1-2, and RAI 4.6.1-3 by letter from NMC to NRC dated April 1, 2005 (NRC 2005-0038). In addition, a detailed review of the Boraflex Monitoring Program was performed during the March 2005 NRC Region III License Renewal Inspection. The results of this review are documented in NRC Inspection Report 2005-005 dated May 2, 2005.

NRC Confirmatory Item CI 4.6.1-2 (Section 4.6.1 - Spent Fuel Pool Storage Rack Boraflex):

The applicant indicated that a predictive code, "EPRI RACKLIFE or its equivalent," will be used to determine which panels will be subjected to full-length testing and to trend and analyze SFP silica level measurement results. The input to the predictive code includes areal density and SFP silica level measurements. The staff is unclear on the ability of the predictive code to project panel degradation if the first areal density test is completed after the beginning of the extended operation period. In RAI 4.6.1-2, dated March 29, 2005, the staff requested the applicant to provide justification regarding the ability of the predictive code to accurately project the condition of the panels to ensure the degradation does not exceed the acceptance criteria with one set of data. In addition, if this justification cannot be made, the staff requested that the applicant commit to conducting a baseline areal density test prior to entering the period of extended operation.

During conversations with the staff, the applicant committed to perform a baseline areal density inspection of the Boraflex panels prior to entering the period of extended operation for predictive code purposes. The applicant will revise its response to reflect this statement. This was identified as confirmatory item (CI) 4.6.1-2.

NMC Response:

The information requested in this confirmatory item, regarding the Boraflex Monitoring Program (LRA Section B2.1.5), was provided in response to NRC Questions RAI 4.6.1-1, RAI 4.6.1-2, and RAI 4.6.1-3 by letter from NMC to NRC dated April 1, 2005 (NRC 2005-0038). In addition, a detailed review of the Boraflex Monitoring Program was performed during the March 2005 NRC Region III License Renewal Inspection. The results of this review are documented in NRC Inspection Report 2005-005 dated May 2, 2005.

NRC Confirmatory Item CI 4.6.1-3 (Section 4.6.1 - Spent Fuel Pool Storage Rack Boraflex):

For the acceptance criteria element, the applicant stated that this element is consistent with the GALL Report. The applicant committed to making appropriate changes to the program if any of the test results indicate that program improvements should be made. However, the staff finds this discussion insufficient for ensuring adequate management of Boraflex degradation. In RAI 4.6.1-3, dated March 29, 2005, the staff requested the applicant to provide more information regarding the Boraflex Monitoring Program's acceptance criteria. Additionally, the staff requested the applicant to provide a discussion regarding the specific corrective actions that will be taken if trends indicate the acceptance criteria may not be met.

During conversations with the staff, the applicant committed to complete an evaluation, within its corrective action program, and increase the frequency of blackness and areal density testing if the silica sample and the areal density trend to a value less than 5% subcriticallity margin, or the acceptance criteria. The applicant committed to provide specific details of the corrective actions that will take place if the acceptance criteria cannot be maintained. The applicant's enhancements to the program and corrective actions are expected to ensure continued material performance. The applicant will revise its response to reflect this statement. This was identified as confirmatory item (CI) 4.6.1-3.

NMC Response:

The information requested in this confirmatory item, regarding the Boraflex Monitoring Program (LRA Section B2.1.5), was provided in response to NRC Questions RAI 4.6.1-1, RAI 4.6.1-2, and RAI 4.6.1-3 by letter from NMC to NRC dated April 1, 2005 (NRC 2005-0038). In addition, a detailed review of the Boraflex Monitoring Program was performed during the March 2005 NRC Region III License Renewal Inspection. The results of this review are documented in NRC Inspection Report 2005-005 dated May 2, 2005.

ENCLOSURE 3

NMC COMMENTS ON TEXT OF THE DRAFT SAFETY EVALUATION REPORT (SER) REGARDING POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2 LICENSE RENEWAL APPLICATION

The following comments are provided to the Nuclear Regulatory Commission (NRC) staff's draft SER with open items regarding the Point Beach Nuclear Plant (PBNP) License Renewal Application (LRA).

Each comment is provided with suggested changes with the suggested revision marked by lineout for suggested text removal and bolded text for suggested additional text. Each comment also has a justification with appropriate references.

Draft SER Comments Section 1

Page, Section, and Paragraph	DSER Text	Suggested Revision	Justification
Page 1-8, Section 1.4.1, Paragraph 1	~~Testing of sprinkler heads should be performed every 50 years and 10 years after initial service.~~	**Sprinkler heads should be replaced or tested in accordance with NFPA 25 prior to exceeding their 50 year service life. If the sprinkler heads are not replaced, the required testing should be repeated at 10 year intervals.**	ISG-4
Page 1-16, CI 4.6.1-1.2	"...the applicant committed to perform areal density and blackness tests once every 2 years during..."	"...the applicant committed to perform areal density and blackness tests **on certain accelerated Boraflex panels** once every 2 years during..."	NRC 2005-0038
Page 1-17, Section 1.7, Paragraph 4	The second license condition requires that the future activities identified in the FSAR supplement be completed prior to entering the period of extended operation.	There are some exceptions to this condition such as PTS..	NRC 2004-0111

Draft SER Comments Section 2

Page, Section, and Paragraph	DSER Text	Suggested Revision	Justification
Page 2-3, Section 2.1.2.1.1 Paragraph 4	Concerning exposure duration, the applicant concluded that long-term exposure to conditions resulting from a failed NSR SSC (such as leakage	Modified via RAI. See CI 2.1-1 Add reference to SER Section 2.1.3.	NRC 2005-0051

Page, Section, and Paragraph	DSER Text	Suggested Revision	Justification
	or spray) is not considered credible. The basis for this conclusion is that leakage/spray would be quickly identified by plant personnel via walkdowns, sump-level trends, or system parameter monitors and alarms. Once identified, appropriate corrective actions would be taken. Therefore, only NSR SSCs whose failure could result in a failure of an SR SSC due to short-term exposure would need to be considered within the scope of license renewal pursuant to 10 CFR 54.4 (a)(2).		
Page 2-6, Section 2.1.2.1.4 Paragraph 4	All portions of the fuel handling system were determined to be within the scope of license renewal, ~~and~~ were moved to the spent fuel cooling system, the containment Units 1 and 2 building structure, or the primary auxiliary building (PAB) structure.	All portions of the fuel handling system **that** were determined to be within the scope of license renewal**,** were moved to the spent fuel cooling system, the containment Units 1 and 2 building structure, or the primary auxiliary building (PAB) structure.	See page 2-41 of LRA.
Page 2-100, Section 2.3.4.1.1, Paragraph 5	• provides for pressure ~~control~~	• provides for pressure **boundary** Pressure Control should be Pressure Boundary in LRA Table 2.3.4-1 page 2-171.	Correction to LRA Table 2.3.4-1 page 2-171. Should have been "pressure boundary", see Table 3.4.2-1 page 3-338 of LRA.

Draft SER Comments Section 3

Page, Section, and Paragraph	DSER Text	Suggested Revision	Justification
Page 3-7, Table 3.0.3-1, Item (B2.1.5) (Boraflex Monitoring Program)	Consistent with ~~exceptions and~~ enhancements	Consistent with enhancements	This program was modified by NRC 2005-0038 to be consistent with GALL.
Page 3-8, Table 3.0.3-1, Item (B2.1.11) (Flow-Accelerated Program)	Consistent with enhancements	Consistent with **exceptions and** enhancements	See NRC 2005-0037 and 2005-0044.
Page 3-30, Section 3.0.3.2.5, Para. 1	The applicant stated that this program is consistent, with ~~exceptions and~~ enhancements, with GALL AMP XI.M22, "Boraflex Monitoring."	The applicant stated that this program is consistent, with enhancements, with GALL AMP XI.M22, "Boraflex Monitoring."	This AMP was modified to be consistent with GALL in NRC 2005-0038.
Page 3-31, Section 3.0.3.2.5, last Para.	...the applicant committed to perform ~~blackness tests prior to and during the period of extended operation once every 2 years.~~	"...the applicant committed to perform **areal density and blackness tests on certain accelerated Boraflex panels once every 2 years during the period of extended operation. The first Boraflex areal density testing of the Boraflex panels will be performed prior to the period of extended operation.**	See comments for pages 4-63 thru 4-66 and NRC 2005-0038.

Page, Section, and Paragraph	DSER Text	Suggested Revision	Justification
Page 3-40, Section 3.0.3.2.7, full Para. 2	The applicant will perform ~~a one-time~~ *inspection of a section of buried fire* pipe prior to the period of extended operation.	The applicant will perform **an** *inspection of a section of buried fire* pipe prior to the period of extended operation.	Clarification. NRC 2005-0026.
Page 3-43, Section 3.0.3.2.7, full Para. 1	In its response to RAI B2.1.7-1, the applicant submitted ... at least every 10 years during the period of extended operation. The staff found that the clarification response to RAI B2.1.7-1 addresses the staff's concerns described in RAI B2.1.7-3.	In its response to RAI B2.1.7-1, the applicant submitted ... at least every 10 years during the period of extended operation. **However, an inspection of opportunity on buried fire protection piping may be substituted for these scheduled inspections.** The staff found that the clarification response to RAI B2.1.7-1 addresses the staff's concerns described in RAI B2.1.7-3.	See the second entry for Page 3-40, Section 3.0.3.2.7, full Para. 2 above. NRC 2005-0026.

Page, Section, and Paragraph	DSER Text	Suggested Revision	Justification
Page 3-45, Section 3.0.3.2.8, full Para. 6	In its response, dated ~~January 21, 2005~~, the applicant deleted this exception and agreed to perform the cable testing, as described in the GALL AMP XI.E3.	In its response, dated **March 15, 2005**, the applicant deleted this exception and agreed to perform the cable testing, as described in the GALL AMP XI.E3 **with exceptions**.	The January 21, 2005 letter (NRC 2005-0009) provided information to support the PBNP definition of significant moisture. Deletion of the exception was done in NRC 2005-0026 (dated March 15, 2005). Neither letter provided agreement to perform cable testing as described in GALL AMP XI.E3. See also the second entry below for Page 3-46, last full paragraph.

Page, Section, and Paragraph	DSER Text	Suggested Revision	Justification
Page 3-54, Section 3.0.3.2.9, Para. 3	The applicant does not routinely perform heat removal capability tests on the EDG and gas turbine-related coolant subsystems. However, operability testing is periodically conducted. ~~The applicant stated that other heat exchangers are heat balance tested. These other tests combined with~~ the operability test ~~and system operability tests~~ provide an indication of the heat flow performance of the EDG and gas turbine-related coolant subsystems. Based on the operability tests~~, tests on other heat exchangers in the system,~~ and successful operation, the staff found this exception acceptable.	The applicant does not routinely perform heat removal capability tests on the EDG and gas turbine-related coolant subsystems. However, operability testing is periodically conducted. **The** operability tests provide an indication of the heat flow performance of the EDG and gas turbine-related coolant subsystems. Based on the operability tests and successful operation, the staff found this exception acceptable.	Clarification - The EDG and gas turbine-related coolant subsystems HXs are <u>not</u> heat balance tested (see LRA Section B2.1.9, page B-105).
Page 3-54, Section 3.0.3.2.9, Para. 4	The continuous operation ~~along with the sampling from other heat exchangers that are heat balanced-tested~~ is an indication that the ventilation chilled water subsystems heat exchangers are performing appropriately. Based on the continuous operation~~, operability tests, tests on other heat exchangers in the system,~~ and past successful operation, the staff found this exception acceptable.	The continuous operation is an indication that the ventilation chilled water subsystems heat exchangers are performing appropriately. Based on the continuous operation and past successful operation, the staff found this exception acceptable.	None of the HXs in the ventilation chilled water system are heat balance tested (see LRA Section B2.1.9, page B-105).

Page, Section, and Paragraph	DSER Text	Suggested Revision	Justification
Page 3-59, Section 3.0.3.2.10, Para. 1	The staff reviewed the information provided by the applicant, as documented in its audit and review report. ~~The staff found that where significant deviations between PBNP fire protection system testing requirements and NFPA codes and standards testing requirements exist, an engineering analysis and justification has been developed to demonstrate that the PBNP fire protection system testing requirements are changed such that an equivalent level of protection is achieved.~~ The staff determined that the applicable NFPA standard in effect at PBNP is NFPA 13, "Standard for the Installation of Sprinkler Systems."...	The staff reviewed the information provided by the applicant, as documented in its audit and review report. The staff determined that the applicable NFPA standard in effect at PBNP is NFPA 13, "Standard for the Installation of Sprinkler Systems." ...	Clarification - NMC has performed a review of NFPA 13 to verify code compliance.

Page, Section, and Paragraph	DSER Text	Suggested Revision	Justification
Page 3-59, Section 3.0.3.2.10, Para. 3	The staff verified that PBNP plans to inspect or replace ~~all~~ sprinkler heads in accordance with NFPA 25. The inspection of ~~some of~~ the sprinkler heads will identify any corrosion, which will then be addressed in accordance with the PBNP corrective action program and therefore accomplish the goal that no biofouling that could cause corrosion will exist. ~~The remaining sprinkler heads will be replaced. Prior to replacement, the sprinkler lines will be flushed and drained, at which time, any loose corrosion products will be evident.~~ The disposition of any corrosion products that are detected will be in accordance with the applicant's corrective action program. On the basis of its review and for the reasons discussed above, the staff found this exception acceptable.	The staff verified that PBNP plans to inspect or replace sprinkler heads in accordance with NFPA 25. The inspection **or replacement** of the sprinkler heads will identify any corrosion, which will then be addressed in accordance with the PBNP corrective action program and therefore accomplish the goal that no biofouling that could cause corrosion will exist. The disposition of any corrosion products that are detected will be in accordance with the applicant's corrective action program. On the basis of its review and for the reasons discussed above, the staff found this exception acceptable.	Clarification LRA Section B2.1.10, Page B-113
Page 3-82, Section 3.0.3.2.16, full Para. 2 – all bullets			These bullets inaccurately paraphrase what PBNP stated/ committed to. See Page 3-147, Para. 2 of the SER for the correct wording.

Page, Section, and Paragraph	DSER Text	Suggested Revision	Justification
Page 3-83, Section 3.0.3.2.16, Para. 5	~~Guide~~ tube split pins are fabricated from nickel-based alloy X-750.	**Unit 1 guide** tube split pins are fabricated from nickel-based alloy X-750. **Unit 2 split pins are fabricated from cold worked 316 stainless steel.**	Unit 2 spilt pins have been replaced during the U2R27 refueling outage.
Page 3-87, Section 3.0.3.2.16, full Para. 1, bullets 1 & 2	The applicant's LRA and the letter NRC-2004-0071, dated July 12, 2004, confirmed that: • The applicant will use industry-wide research studies and initiatives on age-related degradation of RVI components as the basis for determining the inspection methods, inspection method qualifications, inspection frequencies, inspection method acceptance criteria, and corrective actions for the Reactor Vessel Internals Program. • The applicant will implement recommended inspection activities, acceptance criteria, and corrective actions that result from the industry's studies and initiatives on age-related degradation of RVI components as the recommendations apply to the design of the RVIs at the PBNP Units.	See entry above for Page 3-82, Section 3.0.3.2.16, full Para. 2 – all bullets.	The information included in these 2 bullets does not exist in the July 12, 2004 letter or the RAI database for Audit questions.

Page, Section, and Paragraph	DSER Text	Suggested Revision	Justification
Page 3-111, Section 3.0.3.3.1, last Para.	The applicant also stated that (1) the parameters ... (3) the examination methods of this program are ~~adequately linked to either~~ industry or plant operating experience~~; (4) sampling is used to inspect a group of SSCs, the basis and size of the sample inspection population and is based on similarity of construction materials, fabrication and construction details, design, installation, operating environment, and aging effects~~.	The applicant also stated that (1) the parameters ... **and** (3) the examination methods of this program are **capable of detecting the aging effects of concern based on** industry or plant operating experience.	Wording did not agree with the July 12, 2004, (NRC 2004-0071) letter. No sampling is done under PSPM.
Page 3-120, Section 3.0.3.3.3, partial Para.	--- The applicant responded by indicating that visual inspection will consist of 100 percent of the internal tank surface. --- The staff concluded that the program will adequately monitor for internal tank age-related degradation, a 100 percent internal visual inspection of the tank ~~surface~~ and UT thickness measurements of the tank bottom will be performed.	The applicant responded by indicating that visual inspection **of the CST** will consist of 100 percent of the internal tank surface. The staff concluded that the program will adequately monitor for internal tank age-related degradation, a 100 percent internal visual **surface** inspection of the **CST** and UT thickness measurements of the tank bottom will be performed.	This statement only applies to the Condensate Storage Tanks. (NRC 2005-0006)

Page, Section, and Paragraph	DSER Text	Suggested Revision	Justification
Page 3-163, Para. 2, 3, and 4 of Section 3.1.2.3.3	References to "ASME Code Section XI, IWB, IWC, and IWD Inservice Inspection Program" in each of these three paragraphs.	Completely remove references to ASME Inservice Inspection Program in these 3 paragraphs.	LRA Table 3.1.2-2 Loss of material is managed with Water Chemistry Program only. These paragraphs should be essentially the same as those in SER Section 3.1.2.3.4.
Page 3-164, Section 3.1.2.3.5, Para 2 and 3	During the audit the applicant clarified that the use of only the Water Chemistry Control Program was considered sufficient to manage these components because ~~during previous work on the pressurizers these components were visually observed and no records of material loss were recorded. The applicant considered these operating observations equivalent to the purpose of the One-time Inspection Program. Furthermore, the applicant stated that~~ industry operating experience has not identified material loss on these components.	Delete text.	This text should be removed. There is no documentation of this statement being made.

Page, Section, and Paragraph	DSER Text	Suggested Revision	Justification
Page 3-196, Para. 4	Reference to and discussion about One-Time Inspection for managing exterior aging effects	Remove references of and discussion about the One-Time Inspection program.	OTI was not used for managing external aging effects. Two instances in LRA where this is listed (CCW, CS Valves) are in error.
Page 3-213, Para. 2	The applicant stated that the...will be revised...By letter dated July 12, 2004, the applicant committed to revise the	Revise these statements. These statements are not accurate, we did not commit to this.	See July 12 letter pages 12 and 13 of 21 for actual provisions, and LRA Section B2.1.14, page B-149.
Page 3-213, Para. 3	The applicant stated that selective leaching was identified as a potential aging effect~~, and that~~ the Open-Cycle Cooling (Service) Water System Surveillance Program will be revised to ~~include a visual inspection~~ to identify selective leaching ~~to~~ these components. ~~In its letter dated July 12, 2004, the applicant committed to revise the Open-Cycle (Service) Water System Surveillance Program, to include a visual inspection to identify selective leaching of cast iron components.~~	The applicant stated that selective leaching was identified as a potential aging effect. The Open-Cycle Cooling (Service) Water System Surveillance Program will be revised to **credit the One-Time Inspection Program** to identify selective leaching **for** these components. **The One-Time Inspection Program includes a visual inspection and hardness measurements to identify selective leaching of susceptible components.**	Revise these statements. These statements are not accurate, we did not commit to this in the July 12, 2004 letter. Also see NRC 2004-0101, dated Oct. 15, 2004 for commitment regarding selective leaching.

Page, Section, and Paragraph	DSER Text	Suggested Revision	Justification
Page 3-216, Para. 4	Whole paragraph	Delete paragraph. This was not the resolution to the issue being discussed. Replace with discussion pertinent to RAI 3.3.2.1.6-1.	See letter NRC 2005-0026, p. 4 of 21. This issue was reviewed during the Regional inspection, where the Fire Protection Program was reviewed and found to be acceptable for managing these aging effects, as documented in NRC IR 2005-005, dated May 2, 2005.
Page 3-218, 2nd last paragraph	~~In its response, the applicant stated that its~~ Fire Protection Program and Systems Monitoring Program will be revised to ~~include an inspection of these types of components to identify selective leaching, a slowly progressing aging mechanism.~~	**The** Fire Protection Program and Systems Monitoring Program will be revised to **credit the One-Time Inspection Program to identify selective leaching for these components. The One-Time Inspection Program includes a visual inspection and hardness measurements to identify selective leaching of susceptible components.**	See NRC 2004-0101, dated Oct. 15, 2004 for commitment regarding selective leaching.

Page, Section, and Paragraph	DSER Text	Suggested Revision	Justification
Page 3-243, Section 3.4.2.3.2, full Para. 3, 4, & 5	Whole paragraphs	Rewrite paragraphs to deal with only loss of material due to FAC, which is managed with FAC Program and Water Chemistry. Other loss of material effects are addressed in previous paragraphs on page 3-242.	Clarification. Repeating information previously written, and not fully covering FAC.
Page 3-244, Section 3.4.2.3.3, Para. 4 & 5	Whole paragraphs	Rewrite paragraphs to deal with only loss of material due to FAC, which is managed with FAC Program and Water Chemistry. Other loss of material effects are addressed in previous paragraphs on page 3-244.	Clarification. Repeating information previously written, and not fully covering FAC.
Page 3-263, Section 3.5.2.2.1, full Para. 3	The staff found that ~~continuation of the additional inspection measures~~ would provide the assurance of the containment integrity during the period of extended operation.	The staff found that **the ASME Section XI, Subsections IWE & IWL Inservice Inspection Program** would provide the assurance of the containment integrity during the period of extended operation.	Clarification See RAIs 3.5-3 and 2.4-3. See NRC 2004-0086 and NRC 2005-0019 Note: There is no evidence of high concrete temperatures at the Main Feedwater penetrations.

Page, Section, and Paragraph	DSER Text	Suggested Revision	Justification
Page 3-287, Section 3.5.2.3.9, Para. 5	In LRA ~~Section 3.5.2.1.8,~~ the ... ...For the management of ~~this~~ aging effect, the applicant proposed to use the Structures Monitoring Program~~, under which periodic inspections will be performed~~ to ensure that these aging effects are properly managed...	In LRA **Table 3.5.2-8**, the... ...For the management of **these** aging effects, the applicant proposed to use the Structures Monitoring Program to ensure that these aging effects are properly managed. **The Structures Monitoring Program will be revised to credit the One-Time Inspection Program to identify selective leaching for these components. The One-Time Inspection Program includes a visual inspection and hardness measurements to identify selective leaching of susceptible components....**	Clarification See LRA Table 3.5.2-8. See NRC 2004-0101, dated Oct. 15, 2004 for commitment regarding selective leaching.

Draft SER Comments Section 4

Page, Section, and Paragraph	DSER Text	Suggested Revision	Justification
Page 4-12, Section 4.3, Paragraph 2	The applicant discussed the design requirements for components of the reactor coolant system. The reactor vessel ~~and reactor vessel internals~~ were designed and fabricated in accordance with the requirements ~~for Class 1 components~~ stated in the ASME Boiler and Pressure Vessel Code (ASME Code) Section III, ~~1965 Edition through summer 1965 and 1966 Addenda~~. The reactor coolant pressure boundary piping and components were designed and fabricated in accordance with the requirements of USAS B31.1, "Power Piping Code," ~~1967~~ Edition. Other safety-related piping and fittings were also designed and fabricated in accordance with the requirements of USAS B31.1, 1967 Edition.	The applicant discussed the design requirements for components of the reactor coolant system. The reactor vessels were designed and fabricated in accordance with the requirements stated in the ASME Boiler and Pressure Vessel Code (ASME Code) Section III, **1965 Edition for Unit 1 and 1968 Edition through winter 1968 Addenda for Unit 2.** The reactor coolant pressure boundary piping and components were designed and fabricated in accordance with the requirements of USAS B31.1, "Power Piping Code," **1955** Edition. Other safety-related piping and fittings were also designed and fabricated in accordance with the requirements of USAS B31.1, 1967 Also change the words to be in harmony with the 1st paragraph in section 4.3.2.1, which is correct for the reactor vessel internals.	LRA Sections 4.3.1, and 4.3.2

Page, Section, and Paragraph	DSER Text	Suggested Revision	Justification
Page 4-32, Section 4.3.9.2, Paragraph 1 & 3	... the requirements of the USAS B31.1, 1967 Edition, Power Piping Code. ... any PBNP piping system designed to USAS B31.1, 1967 Edition, it is highly unlikely that the 7000-cycle limit will be exceeded for the 60-year life of the plant.	... the requirements of the USAS B31.1, 1967 Edition, Power Piping Code **with the exception of the Reactor Coolant System piping and components which is the 1955 Edition.** ... any PBNP piping system designed to USAS B31.1, 1967 Edition **with the exception of the Reactor Coolant System piping and components which is the 1955 Edition**, it is highly unlikely that the 7000-cycle limit will be exceeded for the 60-year life of the plant.	Clarification
Page 4-34, Paragraph 4	Surge Line Locations. Since the PBNP pressurizer surge lines were designed and constructed to USAS B31.1-~~1967~~, ...	Surge Line Locations. Since the PBNP pressurizer surge lines were designed and constructed to USAS B31.1-**1955**, ...	Clarification

Draft SER Comments Appendix A

Page, Section, and Paragraph	DSER Text	Suggested Revision	Justification
Page A-5, Item No. 23	Implement an enhanced Fire Protection Program.	Prior to the period of extended operation. In the Case of Sprinkler Heads, ~~Inspection~~ **Test** Prior to Exceeding 50-Year Service Life	LRA Appendix A and Appendix B2.1.10 **NRC 2004-0016.** See LRA Section B2.1.10, Page B-113
Page A-5, Item No. 29	~~Completion will be~~ Consistent with Commitments Made in Response to NRC Bulletin 2002-02 and Requirements of NRC Order EA-03-009.	**Prior to Period of Extended Operation and** Consistent with Commitments Made in Response to NRC Bulletin 2002-02 and Requirements of NRC Order EA-03-009. **(Also see Commitment Numbers 58 & 59.)**	Add the following text **NRC 2004-0016** **NRC 2005-0002.**