February 4, 2004

EA-02-031
EA-03-057
EA-03-059
EA-03-181

Mr. Gary Van Middlesworth
Acting Site Vice-President
Point Beach Nuclear Plant
Nuclear Management Company, LLC
6610 Nuclear Road
Two Rivers, WI 54241-9516

SUBJECT: POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2
95003 SUPPLEMENTAL INSPECTION
NRC INSPECTION REPORT 05000266/2003007; 05000301/2003007

Dear Mr. Van Middlesworth:

On December 16, 2003, the results of a three-phase supplemental inspection conducted at the Point Beach Nuclear Plant in accordance with NRC Inspection Procedure (IP) 95003, "Supplemental Inspection for Repetitive Degraded Cornerstones, Multiple Degraded Cornerstones, Multiple Yellow Inputs, or One Red Input," were discussed with Messrs. John Paul Cowan, Douglas Cooper, and Fred Cayia, and members of the Point Beach staff at a public meeting at the Holiday Inn in Manitowoc, Wisconsin. A summary of the public meeting on December 16, 2003, was documented in a letter to Mr. Cayia, dated December 31, 2003. The inspection was an examination of activities conducted under your license as they relate to safety and to compliance with the Commission's rules and regulations and with the conditions of your license. Within these areas, the inspection consisted of a selective review of procedures and representative records, observations of activities, and interviews with personnel.

In a letter dated May 9, 2003, we informed Mr. Cayia of our decision to conduct the IP 95003 supplemental inspection. The inspection was conducted to review your corrective actions for the Red inspection finding associated with the auxiliary feedwater and instrument air systems (AFW/IA) and for the inspection finding associated with the potential common mode failure of the AFW pumps because of plugging of the recirculation line pressure reduction orifices. This second finding associated with the AFW system was subsequently determined to be a Red finding for Unit 2, and a Yellow finding for Unit 1. Details of these findings are provided in Inspection Reports (IRs) 50-266/01-17(DRS); 50-301/01-17(DRS), dated April 3, 2002, and 50-266/02-15(DRP); 50-301/02-15(DRP), dated April 2, 2003, and in Final Significance Determination letters dated July 12, 2002, and December 11, 2003. The inspection also assessed your performance in the Reactor Safety Strategic Performance Area, which included detailed inspections of the effectiveness of your corrective action, emergency preparedness, and engineering programs.

From our inspection, we concluded that your evaluation of the causes of the significant AFW inspection findings was adequate and your proposed corrective actions were reasonable. Though we concluded that generally your planned corrective actions were adequate to prevent problem recurrence, the implementation of some of the corrective actions was weak as reflected in repeated extension of due dates and the lack of quality in the implementation of identified corrective actions. For example, the IP 95003 inspection was extended for one week because of inconsistent quality of your implementation and documentation of corrective actions which resulted in several corrective actions involving the AFW system not being completed. The NRC determined that additional review of corrective actions related to the AFW system was warranted to gain assurance that the system was operable. The NRC subsequently concluded that the AFW system was operable; however, extensive inspection effort was required to verify that previous corrective actions adequately addressed historic AFW system performance problems.

Regarding our assessment of your performance in the Reactor Safety Strategic Performance Area, the NRC determined that the plant is being operated in a manner that ensures public safety. However, the NRC also identified several performance issues which warrant increased attention to ensure continued plant safety. Specifically: (1) the quality of your implementation of programs and processes related to the identification and resolution of problems was inconsistent, resulting in inadequate or incomplete corrective action, (2) we identified multiple findings and violations related to emergency preparedness which indicated that Point Beach management and staff did not have a good understanding of license and regulatory requirements, (3) electrical design basis calculations were poorly controlled, and (4) ineffective communication between engineering and operations contributed to the lack of a common understanding of some system design basis and operational practices.

The NRC determined that your performance improvement plan (Excellence Plan) provides an adequate framework for the improvement of station performance. However, the success of this Plan is contingent on the adequate commitment of resources, the timely and quality implementation of the Plan, and the establishment of measures or indicators of successful completion at various stages during Plan implementation, including when all necessary action steps of the action plans in the Excellence Plan and effectiveness reviews for the actions have been completed. Additionally, we determined that the Excellence Plan did not completely address all problem areas. The Plan required changes to ensure that problems associated with implementation of the corrective action and emergency preparedness programs, engineering design basis calculation adequacy, and organizational effectiveness, are adequately addressed to affect and sustain long-term improvement in these areas.

You are requested to respond to this letter by February 13, 2004, and describe the actions that you will take to address the issues raised during this inspection, and your schedule for submission of your revised Excellence Plan. The NRC will review the adequacy of the revised Excellence Plan and its implementation. The NRC will continue to provide increased oversight of activities at Point Beach until you have demonstrated that your corrective actions are lasting and effective. Consistent with Inspection Manual Chapter (IMC) 0305 “Operating Reactor Assessment Program,” guidance regarding the oversight of plants in the multiple/repetitive degraded cornerstone column of the Action Matrix, the NRC will continue to assess performance at Point Beach and will consider at each quarterly performance assessment review the following options: (1) declaring plant performance to be unacceptable in accordance with the guidance in IMC 0305; (2) transferring to the IMC 0350 “Oversight of Operating Reactor Facilities in a Shutdown Condition with Performance Problems” process; and (3) taking additional regulatory actions, as appropriate. Until you have demonstrated lasting and effective corrective actions, Point Beach will remain in column four of the Action Matrix.

During the inspection, an apparent violation of 10 CFR 50.54(q) and 50.47(b) was identified for changes Point Beach made between October 1998 and December 1999 to the previously NRC-approved Emergency Action Level scheme. This apparent violation is described in Section 3.6 of the enclosed inspection report and in a letter sent to Mr. Cayia, dated December 2, 2003. It was also discussed with Point Beach management during a technical debriefing by the emergency preparedness inspectors on August 8, 2003; at the conclusion of the onsite portion of the emergency preparedness phase of the inspection on August 27; during a preliminary exit meeting for all three phases of the IP 95003 inspection on November 17; during a telephone conference on December 1; and during the public final exit meeting for the IP 95003 inspection on December 16. As discussed in the December 2nd letter, this apparent violation is being considered for escalated enforcement action in accordance with the “General Statement of Policy and Procedure for NRC Enforcement Actions” (Enforcement Policy), NUREG-1600. The current Enforcement Policy is included on the NRC’s website at www.nrc.gov. A predecisional enforcement conference was held on January 13, 2004, in the Region III office. From the information presented at the conference, it was apparent that corrective actions taken, thus far, have been less than fully effective. On January 16, after further discussions between the NRC and NMC representatives about the need to take corrective actions to return to compliance, NMC representatives informed the NRC that the EALs had been changed. A summary of the predecisional enforcement conference was provided to you in a letter dated January 27, 2004. You will be notified by separate correspondence of the results of the NRC’s deliberations on the apparent violation and the adequacy of your corrective actions.

In addition to the apparent violation, the NRC identified that your Emergency Plan and implementing procedures did not provide a range of protective action recommendations as required by NRC regulations. The only protective action recommendation that would have been given to State and local officials by your staff in the event of an emergency at Point Beach was evacuation. This issue is being treated as an unresolved item while the NRC evaluates the potential generic implications. We confirmed by direct observation that the Emergency Plan and implementing procedures have been changed since the inspection was completed to provide an appropriate range of recommendations.

Based on the results of this inspection, ten NRC-identified violations of very low safety significance (Green) and one NRC-identified Severity Level IV violation were identified. Additionally, a licensee-identified violation is listed in Section 5 of this report. These violations are being treated as Non-Cited Violations (NCVs) consistent with Section VI.A of the Enforcement Policy. These NCVs are described in the subject inspection report. If you contest the severity level or significance of these NCVs, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U. S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 801 Warrenville Road, Lisle, IL 60532-4351; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Point Beach Nuclear Plant facility.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and any responses you provide will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records System (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

James L. Caldwell
Regional Administrator

Docket Nos. 50-266; 50-301
License Nos. DPR-24; DPR-27

Enclosure: Inspection Report 05000266/2003007; 05000301/2003007
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-266; 50-301
License Nos:	DPR-24; DPR-27
Report No:	05000266/2003007; 05000301/2003007
Licensee:	Nuclear Management Company, LLC
Facility:	Point Beach Nuclear Plant
Location:	6610 Nuclear Road Two Rivers, WI 54241
Dates:	Corrective Action Inspection, July 28 - August 8, 2003 Emergency Preparedness Inspection, August 4-15, 2003 Engineering, Operations, and Maintenance Inspection, September 8 - October 3, 2003 Preliminary Exit Meeting, November 17, 2003 Public Final Exit Meeting, December 16, 2003
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Enclosure

(Cover page cont)

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SUMMARY OF FINDINGS

IR 05000266/2003-007, 05000301/2003-007; 7/28/2003 - 12/16/2003; Nuclear Management Company, LLC; Point Beach Nuclear Plant, Units 1 and 2. Supplemental inspection 95003 was performed to evaluate corrective actions for a Red inspection finding pertaining to the auxiliary feedwater and instrument air systems, and for a Red inspection finding pertaining to the potential for a common mode failure of the auxiliary feedwater pumps because of the plugging of the recirculation line pressure reduction orifices. The inspection also reviewed the corrective action, emergency preparedness, and engineering programs.

The Nuclear Regulatory Commission (NRC) began the three-phase supplemental inspection on July 28, 2003. At that time, the orifice plugging finding was still considered a preliminary Red finding. However, because the licensee had completed the root cause investigation and had developed and began implementation of corrective actions for the preliminary Red finding before the completion of the inspection, the IP 95003 inspectors reviewed the adequacy of these corrective actions. The Final Significance Determination of the orifice plugging issue was subsequently completed and transmitted to the licensee in a letter dated December 11, 2003. The NRC concluded that this issue was appropriately characterized as Yellow for Unit 1and Red for Unit 2. The difference in significance is a result of the longer time that the orifices were installed in Unit 2.

This inspection was conducted in accordance with NRC Supplemental Inspection Procedure 95003, “Inspection for Repetitive Degraded Cornerstones, Multiple Degraded Cornerstones, Multiple Yellow Inputs, or One Red Input.” In the first phase of the inspection, the licensee’s corrective action program was reviewed, with a focus on problem identification, in general, and implementation of corrective actions for the two AFW issues, in particular.

On August 4, 2003, the second phase of the inspection, a review of the emergency preparedness program, began. An apparent violation was identified during this phase for changes made to the Emergency Action Level scheme that decreased the effectiveness of the Emergency Plan and did not receive prior NRC approval. The licensee was informed of this apparent violation in a letter dated December 2, 2003, and a predecisional enforcement conference to discuss this issue was conducted on January 13, 2004.

On September 8, 2003, the final phase of the inspection began. The focus of this phase was the licensee’s engineering program, particularly design engineering, and additional review of implementation of corrective actions for the two AFW issues. Plant operations and maintenance, as they interact with engineering, were also reviewed. This phase of the inspection was extended an extra week because of problems identified by the inspectors with AFW system corrective actions.

The licensee’s corrective action program was adequate. Examples of poor implementation continue to exist despite licensee efforts to improve overall implementation. Identified program weaknesses that could contribute to implementation problems included the potential for issues to be categorized and analyzed at too low a level and a weak trending process. Recently implemented program improvements were good initiatives but were not formalized.

The overall root and contributing causes for the two AFW Red findings were the lack of understanding of the design, corrective action program weaknesses, and poor operations/engineering interface. And while overall, corrective actions taken for the findings were adequate, several important corrective actions to prevent recurrence had not been adequately implemented.

In emergency preparedness (EP), the inspectors concluded that the licensee's program was adequate. Program challenges and areas needing improvement included EP staff experience level and training, maintenance of EP design bases and understanding of EP regulatory guidance documents. An apparent violation was identified for the failure to maintain a standard emergency action level scheme, and an unresolved item whose significance is greater than Green was identified for a lack of range of protective actions in the Emergency Plan and implementing procedures.

In engineering, the inspectors concluded that the CCW system design and licensing basis were understood and adequately supported by controlled testing and calculations. The 125-volt direct current (VDC) system design basis calculations, however, were poorly controlled and design basis calculations related to several alternating current (AC) systems were poorly understood by engineers. The operability of the electrical systems were verified through calculations by the inspectors. The inspectors determined that communications between operations and engineering staff regarding the understanding of system design and operating practices was not consistently effective.

This report covers a 5-month period of supplemental inspection by NRC contractors and NRC inspectors from all four NRC Regional offices and from Headquarters. Ten Green findings, which were associated with Non-Cited Violations, one Severity Level IV Non-Cited Violation, one apparent violation, and one unresolved item of significance to be determined were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Emergency Preparedness

- Green. The inspectors identified a Non-Cited Violation of emergency planning standard 10 CFR 50.47(b)(2) because the licensee failed to assign onshift responsibilities for reading facility seismic monitors, thereby affecting the ability to timely classify certain seismic emergency events.

  This finding is greater than minor because it was associated with a cornerstone attribute and affected the emergency preparedness cornerstone objective to ensure the adequate protection of the public health and safety. This finding is of very low safety significance because it was a degradation in the emergency response organization (ERO) onshift staffing and did not represent a planning standard function failure. (Section 3.2.b.2)

- Severity Level IV. The inspectors identified a Severity Level IV Non-Cited Violation of 10 CFR 50.9 because the licensee failed to provide complete and accurate information in the submittal of information for the emergency response organization (ERO) performance indicator (PI). Twenty-three onshift communicators should have been tracked and reported in the ERO PI, but were not. The licensee has subsequently submitted corrected PI data to the NRC.

  This issue is greater than minor because it caused the PI to cross the Green-to-White threshold for the 3rd quarter of 2001. Because this issue affected the NRC's ability to perform its regulatory function, it was evaluated with the traditional enforcement process. (Section 3.2.b.3)

- Green. The inspectors identified a Non-Cited Violation of emergency planning standard 10 CFR 50.47(b)(16) because the licensee failed to develop and implement an emergency planning staff training program to ensure that emergency planners were properly trained.

  This finding is greater than minor because it was associated with a cornerstone attribute and affected the emergency preparedness cornerstone objective to ensure the adequate protection of the public health and safety. This finding is of very low safety significance because lack of a staff training program presented a potential degrading condition for the level of qualification and proficiency of the emergency preparedness staff, but did not represent a failure of the planning standard function. (Section 3.5)

- To Be Determined. The inspectors identified an unresolved item for the lack of a range of protective actions in the Emergency Plan and implementing procedures. This issue is being treated as an unresolved item while the NRC evaluates the industry-wide generic implications of this issue. Since the identification of the issue by the inspectors, the licensee has revised the Emergency Plan and implementing procedures to include the appropriate range of protective actions. (Section 3.6.b.1)

- To Be Determined. The inspectors identified an apparent violation of 10 CFR 50.54(q), associated with emergency planning standard 10 CFR 50.47(b)(4), which will be subject to the NRC traditional enforcement process not the revised Reactor Oversight Process. Specifically, the licensee failed to maintain a standard scheme of emergency action levels (EALs). Eight EALs were changed in 1998 and 1999. The changes decreased the effectiveness of the Emergency Plan in that emergency conditions that would have resulted in classifications at the General Emergency (GE), Alert, and Notification of Unusual Event (NOUE) levels would result in a lesser classification under the current EAL scheme. Approval of the NRC was not obtained prior to the changes being made. Since the identification of the issue by the inspectors, the licensee has revised the eight EALs to be equivalent with those approved by the NRC in 1984. (Section 3.6.b.2)

- Green. The inspectors identified a Non-Cited Violation of emergency planning standard 10 CFR 50.47(b)(4) because the licensee failed to properly calibrate the facility seismic monitors to ensure they were capable of supporting implementation of a Notice of Unusual Event EAL.

  This finding is greater than minor because it was associated with a cornerstone attribute and affected the emergency preparedness cornerstone objective to ensure the adequate protection of the public health and safety. This finding is of very low safety significance because a Notice of Unusual Event could still be declared based on ground shaking. (Section 3.6.b.3)

Cornerstone: Mitigating Systems

- Green. The inspectors identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," because Technical Specification Surveillance Requirement 3.8.4.6 for testing the safety-related battery chargers was non-conservative in relation to the design basis calculation for battery charger sizing.

  This finding is greater than minor because it affected the mitigating systems cornerstone objective. This finding is of very low safety significance because it was a design deficiency that did not result in the loss of function. (Section 4.1.1.1.b.1)

- Green. The inspectors identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," because the licensee failed to maintain the 125-volt direct current (VDC) voltage drop calculations accurate and up-to-date.

  This finding is greater than minor because it affected the mitigating systems cornerstone objective. This finding is of very low safety significance because it was a design deficiency that did not result in the loss of function. (Section 4.1.1.1.b.2)

- Green. The inspectors identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action." Specifically, the licensee failed to implement timely corrective action (for over 5 years) for safety-related electrical equipment in the primary auxiliary building (PAB) that was not environmentally qualified, a condition adverse to quality.

  This finding is greater than minor because if left uncorrected, the finding would become a more significant safety concern and have adverse effects on the capability to prevent or mitigate the consequences of accidents. The finding is of very low safety significance because it was a design deficiency that did not result in the loss of function. (Section 4.1.2.b.2.1)

- Green. The inspectors identified a Non-Cited Violation of 10 CFR 50.49(f). Specifically, the licensee identified equipment important to safety located in the primary auxiliary building that would be susceptible to a harsh environment during a postulated high-energy line break but failed to environmentally qualify that equipment.

This finding is greater than minor because if left uncorrected, the finding would become a more significant safety concern and have adverse effects on the capability to prevent or mitigate the consequences of accidents. The finding is of very low safety significance because it was a design deficiency that did not result in the loss of function. (Section 4.1.2.b.2.2)

- Green. The inspectors identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings." Specifically, the licensee failed to include appropriate quantitative setpoint values for the minimum low head safety injection "A" train flow in plant emergency operating procedures (EOPs).

  This finding is greater than minor because it could have affected the mitigating cornerstone objective of ensuring the availability of the low head safety injection system when required to respond to the initiating event. The finding is of very low safety significance because it did not represent an actual loss of safety function. (Section 4.1.5)

- Green. The inspectors identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," because the licensee failed to include in the inservice testing program manual component cooling water (CCW) valves that were required to perform a safety function.

  This finding is greater than minor because it could have affected the mitigating cornerstone objective of ensuring the availability of the CCW or residual heat removal (RHR) systems when required to respond to the initiating event. The finding is of very low safety significance because it did not represent an actual loss of safety function. (Section 4.1.3.2)

- Green. The inspectors identified a Non-Cited Violation of 10 CFR Part 50, Appendix R, Section III.L.1.c. Specifically, the licensee failed to ensure, without the need for "hot standby repairs," adequate control air to the speed controllers for the charging pumps during a postulated fire requiring an alternative shutdown method.

  This finding is greater than minor because the finding would become a more significant safety concern if left uncorrected. The finding is of very low safety significance because it is likely that the licensee would have been successful in completing the repairs and allowing the plant to be maintained in hot standby until cold shutdown could be achieved. (Section 4.1.7)

B. Licensee-Identified Violation

A violation of very low safety significance, which was identified by the licensee, has been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. The violation and the licensee's corrective action tracking number are listed in Section 5 of this report.

REPORT DETAILS

1. Background

In a letter dated July 12, 2002, the NRC issued a Final Significance Determination, classifying a licensee-identified issue with the auxiliary feedwater and instrument air systems (the AFW/IA issue) as a Red finding. The letter also discussed the NRC's decision to perform additional inspection to determine whether the issue should be treated as an old design issue (ODI). The ODI designation referred to the exemption in NRC Inspection Manual Chapter 0305, "Operating Reactor Assessment Program," that allowed the NRC to not take actions specified in the Action Matrix for certain findings. An initial inspection was conducted, by two inspectors, from September 23 - 26, 2002, to review the ODI question.

On October 29, 2002, while the results of the September inspection were being reviewed by Region III management, the licensee notified the NRC of a potential for a common mode failure of the AFW pumps from the plugging by debris of the pressure reduction orifices in the AFW minimum flow recirculation lines. Flow through the recirculation lines is required to prevent damage to the pumps when flow to the steam generators is stopped or significantly reduced by reactor operators. An NRC special inspection team was dispatched to the site on October 30 to review this issue and its relation to the original AFW/IA issue. From its review of the orifice plugging issue, the licensee concluded that the source of the rust-like debris found in the orifice was AFW discharge piping high-point vent valves and pump casing vent valves that had been manipulated during system maintenance. On February 21, 2003, studies conducted at an independent laboratory for the licensee indicated that the sand, silt, and zebra mussel shell debris normally found in plant service water (SW), the safety-related water source for the AFW system, would quickly plug the orifices. The NRC's conclusions from the inspection that the AFW/IA did not qualify as an ODI and that the AFW orifice plugging issue was preliminarily a Red inspection finding were subsequently documented in Inspection Report (IR) 50-266/02-15(DRP); 50-301/02-15(DRP), issued on April 2, 2003.

On May 9, 2003, the NRC issued an Annual Assessment Follow-up Letter, which documented the results of the April 22, 2003, annual Agency Action Review Meeting, including the NRC's decision to perform a supplemental inspection at Point Beach Nuclear Plant (PBNP), using IP 95003, "Supplemental Inspection for Repetitive Degraded Cornerstones, Multiple Degraded Cornerstones, Multiple Yellow Inputs, or One Red Input."

On June 6, 2003, a Regulatory Conference was held to discuss the orifice plugging issue. At that conference, the licensee stated that the results of the analysis of risk from internal events for the issue would be completed later in June and that the analysis of risk from fire would be completed in August 2003. Information related to the risk from internal events was subsequently submitted to the NRC in a letter dated June 27, and information related to the risk from fire was submitted on September 18. The licensee's analysis indicated that the AFW orifice plugging issue was an issue with high importance to safety, a Red inspection finding, for Unit 2, and an issue with substantial importance to safety, a Yellow inspection finding, for Unit 1. The difference in significance between the Units is a result of the longer time that the orifices were installed in Unit 2.

In a letter dated July 18, 2003, the licensee submitted to the NRC selected action plans from its Point Beach Nuclear Plant Excellence Plan, a site-wide, long-term performance improvement plan. In a letter dated December 11, 2003, the NRC issued a Final Significance Determination, classifying the orifice issue as a Red finding.

On July 28, 2003, the NRC commenced the IP 95003 inspection at Point Beach. The IP 95003 inspection was conducted in addition to the scheduled baseline inspections. The intent of IP 95003 is to allow the NRC to obtain a comprehensive understanding of the depth and breadth of safety, organizational, and performance issues at facilities where data indicates the potential for serious performance degradation. The objectives of this inspection procedure are to: (1) provide additional information to be used in deciding whether the continued operation of the facility is acceptable and whether additional regulatory actions are necessary to arrest declining performance, (2) provide an independent assessment of the extent of risk significant issues to aid in the determination of whether an acceptable margin of safety exists, (3) independently evaluate the adequacy of licensee programs and processes used to identify, evaluate, and correct performance issues, (4) independently evaluate the adequacy of programs and processes in the affected strategic performance areas, and (5) provide insight into the overall root and contributing causes of identified performance deficiencies.

As prescribed by IP 95003, the scope of NRC inspection activities at Point Beach included the assessment of performance in the Reactor Safety Strategic Performance Area, including the inspection of key attributes, such as design, human performance, procedure quality, configuration control, and emergency response organizational readiness. Also, the 95003 inspection reviewed the control systems for identifying, assessing, and correcting performance deficiencies (essentially, the corrective action program) to evaluate whether programs are sufficient to prevent further declines in safety that could result in unsafe operation. In developing the scope of this inspection, the NRC considered the results of licensee self-assessment activities and licensee progress in addressing the substantive cross-cutting issue in the area of problem identification and resolution. This issue was discussed in the Annual Assessment Letter, dated March 4, 2003.

As explained in IMC 0305, plants in the multiple/repetitive degraded cornerstone column of the Action Matrix are given consideration at each quarterly performance assessment review for (1) declaring plant performance to be unacceptable in accordance with the guidance in IMC 0305, (2) transferring to the IMC 0350, “Oversight of Operating Reactor Facilities in a Shutdown Condition with Performance Problems,” process, and (3) taking additional regulatory actions, as appropriate.

2. Corrective Action Program

Recent NRC inspections have identified problems with the licensee’s corrective action program. Inspection Report 50-266/02-05; 50-301/02-05, dated May 14, 2002, and

Final Significance Determination Letter, dated June 13, 2002, discuss the corrective action program aspects of a White inspection finding related to the self-revealed failure of a safety injection pump due to gas binding. Inspection Reports 50-266/01-17(DRS); 50-301/01-17(DRS), dated April 3, 2002, and 50-266/02-15(DRP); 50-301/02-15(DRP), and Final Significance Determination Letters dated July 12, 2002, and December 11, 2003, discuss the corrective action program aspects of the Red inspection finding for the AFW/IA issue and of the Red inspection finding for the AFW orifice plugging issue. Additional problems with the corrective action program, which resulted in the NRC identification of a substantive cross-cutting issue in the area of problem identification and resolution, were discussed in the Annual Assessment Letter to the licensee, dated March 4, 2003.

With consideration of these recent problems, the NRC reviewed the corrective action program using the guidance of IP 95003 to evaluate whether the program was sufficient to prevent further declines in safety that could result in unsafe operation. This evaluation was made following inspection of the following six areas:

a. Licensee evaluations of, and corrective actions to, significant performance deficiencies (such as the two Red inspection findings),

b. effectiveness of audits and assessments performed by the quality assurance group, line organizations, and external organizations,

c. process for allocating resources and management of backlogs and workarounds,

d. licensee performance goals and congruence with corrective actions needed to address the documented performance issues,

e. employee willingness to use and effectiveness of the employee concerns program, and

f. effectiveness of the licensee's use of industry information (operating experience) for previously documented performance issues.

In addition to this specific review of the corrective action program, the two other phases of the IP 95003 inspection reviewed corrective action program aspects related to the emergency preparedness area (Section 3 of this report) and the engineering, operations, and maintenance areas (Section 4 of this report).

2.1. Review of Significant Performance Deficiencies

a. Inspection Scope

The inspectors reviewed the licensee's assessments of the two Red findings, focusing on the corrective actions that were identified to prevent recurrence. The inspectors also reviewed the Excellence Plan action plans (11 plans designated as OP-10-001 through -011) to improve corrective action program implementation. Ineffective corrective action had contributed to the AFW findings and was also identified during a recent licensee organizational effectiveness assessment as a key area needing improvement to support overall improvement in plant performance. The inspectors evaluated the corrective action program to identify any weaknesses contributing to ineffective implementation.

b. Observations and Findings

Auxiliary Feedwater System Findings

Overall, the inspectors found the licensee's final evaluation of the two AFW Red findings to be acceptable. However, the inspectors noted that each finding required a revision to the root cause evaluation (RCE), with the AFW/IA Red finding requiring a second revision. This second revision was performed because the initial evaluation and first revision were too narrowly focused.

While the inspectors found that many corrective actions for the AFW findings had been completed, there remained a number of outstanding corrective actions, including corrective actions to prevent recurrence (CATPRs). For these CATPRs, little progress had been made, to date, and for some corrective actions the due dates had been significantly extended. The inspectors also found weak implementation of several corrective actions. Also, many actions related to the AFW safety system functional assessment (SSFA), which was performed as a corrective action to the AFW/IA Red finding, were not complete.

Finally, changes required to important documents, including the AFW design basis document (DBD), final safety analysis report (FSAR), calculations, and inservice test program (IST) bases, and others had been identified as necessary but were not yet completed. Only some of the outstanding actions associated with the AFW system were captured in the Excellence Plan (in action plans OP-13-008, "Gain Additional Design Margin in the Auxiliary Feedwater System," OP-14-008, "AFW Design Basis Validation Project," EQ-15-014, "Auxiliary Feedwater Orifice Replacement," and EQ-15-015, "Auxiliary Feedwater Electrical Modifications"), others were captured in the corrective action program. Some of the actions in the Excellence Plan had completion dates in 2005 and 2006, which the inspectors considered to be untimely. The inspectors determined that, overall, the actions taken to prevent recurrence related to the two AFW findings were adequate though some specific actions were not consistently implemented in a timely and effective manner.

A detailed review of the corrective actions to prevent recurrence for each of the AFW findings follows.

b.1 AFW Orifice Plugging

The inspectors reviewed RCE 191, "Possible Common Mode Failure of Aux Feed Recirculation Lines," Revision 1. This revision was based on a request from the Corrective Action Review Board (CARB) to include the management oversight element as an organizational root cause. The report was completed approximately six months after the event. The RCE was performed by a team and aided by an independent review. Two root causes were identified. The direct root cause was the failure of the design engineer to properly evaluate within the design process the potential for orifice plugging. The organizational root cause was less than adequate management oversight of the design modification process. Several contributing causes were also identified, including inadequate knowledge of AFW recirculation line design functions, misapplication of vendor information, omission of information on design functions from the safety evaluation, and inadequate independent verification.

An extent of condition assessment of other flow-restricting orifices in the plant was conducted to determine if the potential for plugging and impacting other system safety functions existed. No other safety-related flow restriction devices were found to be susceptible. The licensee did not perform a separate extent of condition for the root causes. The report stated, "The extent of condition or generic implications of the organizational root cause (less than adequate management oversight of the design modification process) has been addressed through the Organizational Effectiveness Assessment." The organizational effectiveness assessment was completed early in 2003 prior to the completion of the RCE. Because the assessment was very broad and did not specifically evaluate which parts of the assessment addressed the extent of cause for the AFW issue, the inspectors could not determine which issues identified in the organizational effectiveness assessment were related to the causes of the AFW orifice plugging issue.

The inspectors reviewed the implementation of the CATPRs specified in RCE 191. Four CATPRs were specified. A review of the implementation and effectiveness of each action follows:

- CATPR #1: Implement periodic reviews of Engineering's products by the Quality Review Team to identify and address human performance related issues.

  The inspectors found that this action had been inconsistently implemented. The Quality Review Team (QRT) was formed in November 2002. Between November 2002 and September 2003, a total of 64 engineering products had been reviewed and graded for quality. However, a significant number of the reviews (28) were conducted in January, shortly after the process was implemented. From February through June, QRT reviews of engineering products was sporadic, ranging from 1 product reviewed to 8 products reviewed per month. No engineering products were reviewed in July or August 2003. The licensee indicated that the reviews were not conducted due to other higher priority work but that the QRT would review a larger than normal sample in September. In response to the inspectors' questions regarding QRT reviews, the licensee identified that corrective action program problem identification documents (CAPs) had not been written for engineering products that were graded "3." A grade of "3" indicated minor errors and per the guidance of Nuclear Plant Business Unit Procedure (NP) 7.1.7, "Quality Review Team," should have been documented in a CAP. The CAPs were subsequently generated to capture the results of the reviews.

- CATPR #2: Increase engineering management involvement in the approval and oversight of modifications.

The action was implemented through the creation of the Design Review Board (DRB) process. The DRB process included both a review of the modification in the conceptual phase and a review of the final design. The DRB included staff from various departments and was intended to provide a comprehensive multi-disciplined review of the modification. The inspectors attended two DRB meetings and reviewed the meeting minutes for all other meetings. The meetings appeared to have been productive and clearly increased the involvement of departments other than engineering. In all but one DRB, the chairman was the Manager of Design Engineering, consistent with the intent of the CATPR to increase engineering management involvement in the approval and oversight of modifications; however, the DRB Procedure (NP 7.2.12, “Design Review Board”) allowed a design engineering supervisor (first-line supervisor) or designee to chair the DRB. The inspectors were concerned that without specific procedural guidance to ensure (upper) management involvement in the DRB process, this involvement could not be assured. The licensee wrote CAP050120 to review management participation in DRBs.

- CATPR #3: Present lessons learned from this event to all engineering personnel stressing the importance of following the Design Process.

  A lessons-learned session had been recently conducted through continuing training for the engineering staff. The inspectors reviewed LP ESC-03-LP016, “Lessons Learned from Possible Common Mode Failure of the AFW System,” and discussed the sessions with engineering staff who had attended. The lesson plan accurately described the AFW issues and the results of the root cause evaluation. Personnel interviewed indicated that the training was informative and useful.

- CATPR #4: Implement FP-E-MOD-07, “Design Verification and Technical Review,” dated December 27, 2002, in accordance with normal implementation process.

  The action specified was to implement the NMC or “fleet” modification procedure. This had not yet been completed at the time of the inspection but was planned for the end of September 2003. The inspectors reviewed a draft of the new procedure and the existing Procedure NP 7.2.2, “Design Control,” and determined that there was no substantial difference in the requirements for design verification. As a result, the inspectors concluded that this action was not a corrective action that would prevent recurrence of the AFW orifice plugging event. The inspectors’ observations on the two procedures and the inspectors’ conclusion were included in CAP050177, and the licensee subsequently wrote a Point Beach-specific procedure (NP 7.2.15, “Fleet Modification Process”), with improvements, to implement the fleet procedure. The licensee also revised existing modification/design-related procedures, including NP 7.2.2, to incorporate similar improvements.

b.2 AFW Instrument Air Finding

The inspectors reviewed the second revision of the RCE for the AFW/IA finding. RCE000202, “Potential AFW Pump Damage Due to Low Flow That Results in Increased Core Damage Frequency,” contained the following statement:

> On or about 3/7/03, station management concluded that the problem statement (and therefore the identification of the root cause) for RCE 01-069, Revision 1 was narrowly focused. Management considered that the RCE focused on procedural inadequacies and did not sufficiently consider potential system design problems. As a result, other issues that could impact minimum recirculation flow requirements were not identified. Management commissioned an independent root cause evaluation team to perform RCE000202 with the following problem statement:

RCE000202
Problem Statement
The purpose of this investigation is to determine the root and contributing causes of potential Auxiliary Feedwater Pump (AFWP) damage due to low flow that results in increased Core Damage Frequency (CDF).

Revision 2 of RCE000202 was dated April 9, 2003, which was 1 year and 4 months after the event. Two root causes were identified. The first root cause was the failure to consider the integration of AFW system design and accident progression. The second root cause was less than adequate knowledge of the safety significance of the AFW recirculation line in protecting the pumps. Three contributing causes were identified and included a lack of problem and issue ownership, less than adequate engineering/operations interface, and less than adequate management of the interrelationship of documents.

Overall, the inspectors found the final root cause evaluation to be adequate. However, a shortcoming in addressing the extent of cause similar to the AFW orifice plugging issue was identified. In addressing a contributing cause of "Lack of problem and issue ownership," the report stated:

> The RCE Team considers that, in addition to the specific actions identified above, improvements in the Corrective Action Process are desired. No specific corrective actions are necessary because recent initiatives should meet that goal.

Similar to the AFW orifice plugging extent of cause, no specific evaluation was conducted. Instead the licensee credited a separate initiative without ensuring that the initiative truly addressed the extent of cause. The inspectors could not determine if the recent corrective action program initiatives addressed improvements identified by the RCE team because they were not specified.

The inspectors reviewed the implementation and effectiveness of the eight CATPRs (designated by the licensee as corrective actions (CAs):

- CA29830: Revise “Design Input Checklist”

  This corrective action was initially closed without revising the checklist. The failure to complete the action as specified was identified by the Technical Review Panel, a newly formed group that reviewed completed corrective actions. The checklist was then revised.

- CA29831: “Upgrade the EOP/AOP [Emergency Operating Procedure/Abnormal Operating Procedure] change process to ensure the steps to mitigate the accident are not in conflict with the design and current licensing basis.

  The action was completed as specified.

- CA29832: Develop a strategy and schedule to train individuals on the interrelationship between system design and current licensing basis. (Operations)

  CA29833: Develop a strategy and schedule to train individuals on the interrelationship between system design and current licensing basis. (Engineering)

  These two actions were the same for two different groups, operations and engineering. The intent of the actions was to cover systems other than AFW. The action for the operations department was extended to July 2004 to allow time for the reconstitution of the current licensing basis (CLB). Reconstitution of the CLB was specified in a non-docketed Excellence Plan action plan (OP-14-004, “Reduce Ambiguity of Current Licensing Basis for User”) and was a long-term project extending out several years, with the first set of systems to be completed in 2004.

  The action for the engineering department was complete, although a firm schedule and strategy had not yet been developed and approved by CARB. The closure was based on an internal memo from the engineering department to the training department with a recommended approach to the training which included a focus group effort to determine the topics for training. This memo also indicated that a finalized detailed class schedule would be developed by January 21, 2004. The inspectors reviewed the engineering training schedule for 2004 and determined that this training had not yet been incorporated into the schedule. The licensee acknowledged that the training would have to be added to the schedule once the training was developed.

  The inspectors considered these actions to be among the most important corrective actions to prevent recurrence as they directly addressed both of the root causes identified and extended beyond the AFW system to other important systems. However, licensee action, to date, had not been timely or sufficient to ensure that the training specified by this CATPR would be conducted and would be effective to prevent recurrence. The licensee wrote CA053525, 053526, and 053527 to address the timing of the training.

- CA29834: Conduct a detailed review of the AFW system to identify what modifications must be performed to ensure minimum flow is always available in all modes for pump protection. Operator action should be minimized if not eliminated.

  The inspectors considered that this detailed review was not really a CATPR, but that the actions taken to address problems identified by the review were actually CATPRs. Many of these actions were not yet completed. The licensee had an external, independent team conduct a safety system functional assessment (SSFA) of the AFW system and also performed an internal review focusing on electrical power supplies to AFW system components. The SSFA identified some issues with the AFW system that required correction but determined that the system remained operable. The inspectors reviewed a sample of issues identified by the SSFA and the planned corrective actions.

  Prior to the SSFA, and as a result of questions from NRC inspectors during the special inspection conducted in 2002 (IR 50-266/02-15(DRP); 50-301/02-15(DRP)), the licensee identified an issue with common power supplies to the SW valves to the AFW pump suction. Under certain plant electrical configurations, the potential existed for a common mode failure of three of four SW motor-operated valves (MOVs) during a postulated seismic event. This operable but degraded condition required compensatory measures, including additional required operator action outside the control room. An electrical modification was planned to eliminate the problem and was included in an Excellence Plan action plan (EQ-15-015, “Auxiliary Feedwater Electrical Modifications”); however, the installation of the modification was not scheduled to be completed until the 4th quarter of 2005. In response to the inspectors’ questioning the timeliness of this action, the licensee moved up the scheduled installation of the modifications and completed the last one in December 2003.

  The SSFA identified that the motor-driven AFW pumps were operable but degraded because of nonconservative IST test criteria for pump differential pressure. The test criteria had been developed assuming a main steam safety relief valve setpoint tolerance of 1 percent, when the Technical Specifications (TSs) allowed 3 percent. The licensee determined that the motor-driven pumps did not have enough hydraulic margin to overcome the additional pressure. The pumps were considered operable but degraded because recent main steam safety valve testing had shown the valves lifting within 1 percent of the setpoint. The licensee identified several corrective actions, including calculation revisions and potential capacity upgrades to the AFW system, to restore the pumps to fully operable. None of the actions had been completed at the end of the inspection. The capacity upgrades were tracked in an Excellence Plan action plan (OP-13-008, “Gain Additional Design Margin in the Auxiliary Feedwater System”) that was not docketed. The other corrective actions were tracked only in the corrective action program.

- CA29835: Develop a lesson plan to train individuals on the safety-related functions of the AFW system.

  CA29836: Develop a schedule to train individuals on the safety-related functions of the AFW system.

  Both of these CATPRs were extended until mid-2004, as with CA29832, because of the need to first reconstitute the CLB. The inspectors questioned the timeliness of this training given that the reviews of the AFW design and licensing basis were complete. The inspectors considered these actions to be untimely as the actual training would not likely occur until late in 2004, while the first AFW issue was identified in 2001 and the second AFW issue was identified in 2002. The licensee wrote CAP050108 in response to this concern and initiated CA052332 to reevaluate the due date of the action. The training was subsequently completed in early December 2003.

- CA29837: Assign an Issue Manager to coordinate the implementation of changes to DBD-01, FSAR, IST basis, TSs, TRQM [Technical Requirements Manual], and EOPs to ensure consistency in Safety-Related Function descriptions related to the AFW system include the appropriate reference(s) for all of the safety-related components and functions in DBD-01.

  This action was closed and the supervisor of the newly developed Configuration Management group was assigned as the Issue Manager. The inspectors noted that the assignment of an Issue Manager was not really a CATPR, but rather the actual correction of the information in the documents was the corrective action to prevent recurrence. The licensee identified the need to make changes to these documents through several different efforts, including the RCEs, the AFW SSFA, and the AFW system self-assessment report. However, there was no single tracking system or method in place to ensure that all of the required changes would, in fact, be made. Many of the changes needed were identified in CAPs and assigned to various people, some of whom were outside of the Issue Manager’s department. During an interview, the Issue Manager indicated that many of the changes would be coordinated through Excellence Plan action plan OP-14-008, “AFW Design Basis Validation Project,” but that some of the issues would be addressed through the corrective action program. The Excellence Plan action plan had one outstanding action item (OP-14-008.7) to revalidate the AFW design basis, which was due in the third quarter of 2006. There was a similar Excellence Plan action plan OP-14-003, “Validate Design Bases for High Risk Systems,” which called for the validation of the design basis for seven different systems, including AFW. Step 14-003.6, which was the actual validation effort was scheduled to start in the third quarter of 2004 and finish in the third quarter of 2006. Because of the lack of a detailed plan with due dates, the inspectors could not conclude that the updates would be completed prior to 2006, which was not considered to be timely corrective action for the AFW issues that occurred in 2001 and 2002.

  During the inspectors’ review of AFW issues, it became apparent that the Issue Manager was not consistently aware of activities related to the AFW system.

Subsequently, the inspectors determined that no specific guidance or expectations regarding Issue Manager duties and responsibilities existed. The licensee wrote CAP050590 to document and track corrective actions related to the failure to provide formal guidance that defines management expectations regarding Issue Manager duties and responsibilities. Overall, the inspectors determined that the licensee had not defined the responsibilities of an issue manager, and that this CATPR had not been effectively implemented.

b.3 Corrective Action Program Issues

The inspectors reviewed the Excellence Plan action plans (OP-10-001 through -011) for improving the corrective action program. Many improvement initiatives had only recently been implemented and the long-term effectiveness of the initiatives could not yet be determined. In addition, most of the initiatives had not been proceduralized and, therefore, the inspectors concluded that sustained improvement to the corrective action program effectiveness could not be fully assured.

The inspectors identified a number of weak areas that may have contributed to the ineffective implementation of the corrective action program associated with the significant performance deficiencies. Overall, the inspectors found the program to be designed to achieve flexibility and management discretion. The program was implemented in a manner that maximized reporting of problems and did not overextend resources to resolve them. According to licensee personnel, the number of CAPs was expected to rise from about 3500 - 4000/year to 7000 - 8000/year. The flexibility of the corrective action program came with the many procedularized recommendations for assigning significance levels, performing evaluations, and implementing corrective actions and a limited number of requirements. As the program had so few requirements, there were risks of inappropriately limiting the extent of analysis and correction of the identified issue.

The inspectors had additional observations of the corrective action program, as discussed below. These observations were documented by the licensee in CAP050177.

Significance Level. Four significance levels (A, B, C, and D) were specified with examples listed in a matrix to help assign the level. Level A (significant) issues included significant conditions adverse to quality, level B (moderate) issues included conditions adverse to quality, level C (minor) issues were other problems, while level D issues were improvements. Moderate and minor were not defined. The inspectors noted that the examples listed in the matrix were generally event- or outcome-based. That is, if a significant plant effect occurred, the issue would be assigned a higher significance level. Potentially significant issues, if they did not result in a plant effect, were likely to be considered a level C or minor issue. Applying the criteria in this manner could result in missed opportunities to proactively evaluate and correct issues and conditions before a plant effect was seen. As an example, there were no specific criteria to evaluate the significance of a failure to implement a corrective action or of a engineering problem such as a deficient calculation. Based on the inspectors' observations, these types of issues would generally be considered minor, or not conditions adverse to quality, unless there was a plant effect.

Five activity types or evaluations were used: RCE, apparent cause evaluation (ACE), condition evaluation (CE), maintenance rule evaluation (MRE), and operability request (OPR). RCEs were expected for level A CAPs and justification was required for exceptions. No causal analysis (RCE or ACE) was required for any significance level below A.

While onsite, the inspectors observed that a CE was used for some level B issues. The licensee recently wrote CAP034566 to document that compared to industry norms, the number of RCEs and ACEs had been very low as related to site performance. Overall, the inspectors concluded that the licensee identified a lot of issues but did not always evaluate them at a high enough level. The inspectors did not identify any specific examples where an issue was not adequately evaluated, though the process could allow for a review to be performed that was not commensurate with the potential significance of an issue.

<u>Change Provisions</u>. The procedural requirement to document the justification to not perform a RCE for a level A CAP was not always followed. At a CARB meeting on August 4, 2003, the inspectors noted that three of four evaluation reports did not have the required justification. The licensee wrote CAP034598 to document this problem.

While changes in evaluation to raise the level of evaluation must be approved, there were no lower level activities upgraded to an RCE observed by the inspectors. Changes from an ACE to a CE and vice versa were observed.

<u>Automatic Triggers</u>. There are no automatic triggers defined by the corrective action program to escalate evaluation levels (for example, three level C CAPs on the same issue within a month moves the latest of the three CAPs to a level B). Consequently, the risk of missing an adverse performance trend was increased. The lack of automatic triggers to escalate an issue may also contribute to the potential for issues to be under analyzed.

<u>Analytical Methods</u>. Only level A issues received an RCE, the only activity level for which use of analytical cause evaluation methodology was expected. Section 4, Requirements, of OEG 001, “Root Cause Evaluation Manual,” the licensee’s guidance document, consistently applied the term "should." In fact, the use of the manual itself was "recommended, but not mandatory.” For ACEs, no formal cause evaluation methods were required to be used, although the program provided that lower level analytical methods <u>may</u> be used for ACEs. The 2-5 hours estimated level of effort for an ACE was inconsistent with the suggested guidance to use an analytical method and perform an extent of condition review. In summary, only about 1 percent of all CAPs received any level of evaluation through an analytical method.

<u>Teams</u>. There was no requirement to have investigative teams, even for an RCE. As a part of the recent corrective action program improvement initiatives, the licensee began to emphasize the use of teams, including interdisciplinary teams. However, use of a team was not required. The inspectors noted that a recently formed RCE team to review an issue (CAP033997, “Unit 2 Main Feed Pump Trip Results in a Unit 2 Reactor Trip”) consisted of team members only from the engineering department.

Independence. There was no requirement for independence anywhere in the process. In fact, issues were routinely assigned to the department most closely associated with the issue. For example, an engineering issue would be assigned to the engineering department and a maintenance issue to the maintenance department for action. While this approach may encourage ownership, it did not provide the independence needed for a different, more impartial perspective. The inspectors did recognize that the Technical Review Board, though not a requirement, involved staff from various departments which provided effective independent assessments of the adequacy of corrective actions.

Training. Training was not required but was expected for root cause evaluators. Licensee management expectation was that each RCE team should have at least one member trained in analytical cause evaluation techniques. The charter for RCE000205 (for level A, CAP033889, "Unit 1 Flux Map Detectors Failing") listed a team lead who was not on the qualified lead investigator list although the team lead had attended equipment root cause training in June 2003. Two other members were assigned, neither of whom appeared on the training or RCE qualified lists. Recently, RCE refresher training was conducted as part of the corrective action program improvement initiatives, although there was no requirement for refresher training.

Training was not required for conducting ACEs and there were no qualification requirements included in the procedures for conducting ACEs. However, ACE training was conducted recently also as part of the corrective action program improvement initiatives.

Corrective Action Program and Work Order Process. The inspectors reviewed the corrective action program and the work order (WO) process to determine the relationship between the two. The corrective action program was controlled by an NMC procedure and the WO process was controlled by a Point Beach procedure; the procedures contradicted each other. The WO procedure (NP 10.2.4) allowed a CAP to be closed to a WO when the WO was initiated. The corrective action program procedure (NP 5.3.1, Attachment 6) indicated that the CAP could not be closed until the actual work was complete. The inspectors noted that the procedures did not require feedback to the CAP process if a WO was closed that was associated with a level B CAP, a condition adverse to quality. The licensee wrote CA052067 to resolve the discrepancy between the two procedures and NP 5.3.1 was subsequently revised on October 29, 2003, to bring the two procedures into agreement.

Effectiveness Review. Effectiveness reviews were expected, per procedure, for a majority of RCEs. However, there were eight justifications for not doing one, including having no corrective actions to prevent recurrence (CATPRs). There was no mention of effectiveness reviews for any other type of corrective actions or for any activity type other than RCE. The inspectors determined that the requirements to perform effectiveness reviews were limited. Considering the number of observations regarding ineffective corrective action implementation documented in this report this is an area warranting additional emphasis by the station.

Trending. The corrective action program depended upon trending of items below level A (and for A level issues not subject to RCEs) to identify in aggregate those things not individually meriting an RCE. Given the increase in CAPs generated and the lowered threshold for reporting issues, the licensee was relying on trending to identify when to perform a causal analysis and take additional corrective action. However, the inspectors found that the trending program was not adequately serving the intended purpose. Each department performed trending, with some departments trending what happened, and other departments trending causal and human performance information. The ability of the trending function to provide a trigger to identify issues or conditions requiring additional evaluation was diminished by several factors. The method for coding a CAP only allowed one entry for each of the coding areas; therefore, all of the information, particularly causes discussed in the ACE/RCE, were not being trended. To the extent that ACEs (for which an apparent, not a root cause, was expected) did not provide valid causal information, the trending of causes was suspect. The licensee recently identified in CAP034566 that for the 2nd quarter of 2003 only about 50 conditions were coded in the "why" codes. This amount of data would not be meaningful for trending. The inspectors found several examples where causes identified did not match the cause code applied:

- RCE000182/CAP002968: The CAP indicated that the “Human Performance Failure Mode” was “K6 - Inadequate Standards Knowledge.” The RCE “Human Performance Failure Modes” were: 1. Inadequate Communications; 2. Tunnel Vision; 3. Wrong Assumptions; 4. Inadequate Verification. Of these reasons, only Tunnel Vision was “Knowledge” based. As a result, the three other human performance failure modes identified in the RCE were not captured in the trending program.

- RCE000192/CAP030002: The CAP indicated that the “Human Performance Failure Mode” was “Unknown.” The RCE stated that the cause was “Lack of ownership and a flawed mental model of the Cold Weather Preparations process.” There were several “Significant Contributing Causes”: 1. Inadequate Understanding of the Program’s Scope; 2. Inadequate Implementation of Corrective Actions From Previous Events and Assessments; 3. Ineffective Use of Operational Experience (OE); 4. Inadequate Work Control/Management of Cold Weather Preparations.

In addition to the process weaknesses noted above, work load may hamper the effectiveness of the corrective action program. There were a number of indications that the corrective action program-related workload was heavy. The Performance Assessment Department had routinely worked 60-hour weeks for about 6 months. Except for filling a position vacated by retirement, the inspectors were not made aware of any plans to increase the number of personnel in the department, despite a significant increase in the number of CAPs being generated and additional corrective action program-related duties that had been added as part of the improvement initiatives.

2.2 Effectiveness of Audits and Assessments

a. Inspection Scope

The inspectors reviewed several Nuclear Oversight (NOS–quality assurance) quarterly reports from 2002 to present, focusing on NOS findings related to the effectiveness of the corrective action program. The inspectors also reviewed a recent self-assessment of NOS effectiveness and interviewed the NOS manager. The Excellence Plan contained an action plan (OR-02-001, "Nuclear Oversight Effectiveness") for improving NOS effectiveness, but many of the action steps had not yet been completed.

b. Observations and Findings

Based on review of the reports and interviews, the inspectors concluded that the NOS reports had identified numerous problems with the Point Beach corrective action program. Specifics of the problems identified are discussed below.

1Q2002 - NOS assessed the overall effectiveness of the Quality Assurance Program (which included the corrective action program) at Point Beach as adequate/attention warranted for the first quarter of 2002. NOS identified multiple examples of untimely corrective actions such as 14 operability determinations greater than 2 years which were still open. NOS wrote CAP002777, "Untimely Corrective Actions - Failure to Establish Qualification Files for Equipment Credited for Operating in a High Energy Line Break (Operability Determination 98-0164)," which was classified as a significant QA finding to document and disposition the concern regarding untimely corrective actions. RCE000051 was conducted from April 8 through June 13, 2002, as part of CAP002777. The purpose of the RCE was to determine why it was taking more than 4 years to resolve outstanding operable but nonconforming issues. The untimely corrective actions for the original high energy line break issue are discussed further in Section 4.1.2 of this report.

4Q2002 - NOS assessed the overall effectiveness of the Quality Assurance Program at Point Beach as adequate/attention warranted for the fourth quarter of 2002. NOS continued to identify problems with implementation of the corrective action program, particularly with the timeliness of corrective actions. A comment in the report stated: "From CA program problems identified, NOS concluded that they had been inconsistent in getting line management to fully understand significance of issues, and resolving the issues in a timely manner." NOS wrote CAP030664 to document its findings of untimely corrective actions.

1Q2003 - NOS assessed the overall effectiveness of the Quality Assurance Program at Point Beach as adequate/attention warranted for the first quarter of 2003. NOS identified weaknesses in almost every phase of the operating experience program.

Assessment PBSA NOS-03-03 - This assessment was performed to determine the effectiveness of NOS. There were several recommendations in the report to improve performance of NOS. This assessment stated that NOS reports did not pursue major weaknesses they identified, such as the corrective action program deficiencies. An issue identified in the assessment was that NOS did not adequately "Drill Down" into identified issues to adequately identify causes.

The inspectors concluded that NOS had been ineffective in resolution of their findings concerning inadequate implementation of the corrective action program at Point Beach. The majority of the untimely corrective actions addressed in RCE000051 remain unresolved, more than 1 year after the RCE was issued. Proposed improvements to NOS were addressed in Excellence Plan action plan OR-02-001. The majority of the improvements will not be implemented until late 2003 and 2004.

2.3 Employee Concerns Program and Safety Conscious Work Environment

a. Inspection Scope

The inspectors reviewed the program requirements, interviewed the employee concerns program (ECP) site contact, and reviewed several recent ECP files to assess the safety conscious work environment and to determine if safety-significant issues in the ECP program received the proper level of attention. The inspectors also reviewed the results of a site culture survey conducted in late 2002. Also, the inspectors interviewed plant personnel to assess the safety conscious work environment.

b. Observations and Findings

The ECP files reviewed did not involve safety-related plant systems and did not reveal any issues that would indicate safety conscious work environment problems. Individuals interviewed did not express any concerns regarding the work environment and all indicated that they felt comfortable with raising issues to plant management; however, there was a perception that corporate management was too involved in the characterization of risk-significant issues.

The results of the culture survey did not identify any issues with the safety conscious work environment but did reveal that there was a lack of employee confidence in the effectiveness of the corrective action program. The survey also found that there were some issues with the general work culture, including workload and priorities. The inspectors also reviewed the corrective action program self-assessment results from mid-2002 which stated that 12 percent of employees interviewed indicate some reluctance to initiate CAPs. Further follow-up by the ECP staff found that the reluctance to write a CAP was not a reluctance to identify safety issues but rather resulted from the "boomerang effect" in which the employee who initiated a CAP was assigned the CAP for resolution, thus adding to the employee's workload. The follow-up interviews also found that the reluctance was related to employees not wanting to get their co-workers "in trouble" by writing CAPs for low-level errors that they may have committed.

The licensee factored the results of the culture survey and the 2002 corrective action program self-assessment into the Excellence Plan action plans to address changes in the ECP (action plan OR-03-001, "ECP Integrated Program Improvements") and in the corrective action program (action plans OP-10-001 through -011, "Corrective Action

Program"). The licensee stated that another site culture survey will be conducted in late-2004 to measure the results of these changes, as well as the other significant organizational changes at the site.

2.4 Licensee Performance Goals

a. Inspection Scope

The inspectors reviewed the licensee's business plan and incentive program for 2003-2004 to determine if the goals in these plans conflicted with the required activities outlined in the Excellence Plan to improve plant performance (action plans OR-06-001, "Five Year Strategic Planning Process," and OR-06-002, "2003 Business Plan and Excellence Plan Rollout").

b. Observations and Findings

The inspectors reviewed the licensee's business plan and incentive program and determined that there did not appear to be any conflict between the goals of these programs and the actions needed to correct the identified performance issues. In fact, the business plan was used as an input into the development of the Excellence Plan. Overall, there appeared to be alignment of the goals in the plans reviewed.

2.5 Allocation of Resources

a. Inspection Scope

The inspectors reviewed corrective action items, attended plant meetings, interviewed staff and management, and reviewed the Excellence Plan action plans to assess if the licensee had appropriately allocated resources to correct the identified performance deficiencies (action plans EQ-15-001 through -018, "Equipment Reliability"; OP-10-001 through -011, "Corrective Action Program"; and OP-14-001 through -008, "Configuration Management").

b. Observations and Findings

The inspectors found many indications of competing priorities and a large workload that affected the quality and timeliness of some licensee corrective actions. For example, in the interviews conducted by the licensee for the root cause evaluation for possible common mode failure of the AFW recirculation lines (RCE000191), several engineers indicated that time and schedule pressure contributed to the inadequate design review associated with upgrading the safety classification of the recirculation lines. Further information from the interviews indicated that this situation was not unique and that other modifications had been similarly hurried. Additionally, one of the corrective actions to prevent recurrence was to establish the DRB to review engineering products. However, during the inspection, the licensee identified that the DRB had been canceled on several recent occasions due to the lack of availability of the assigned staff. The inspectors noted cancellations of other meetings and numerous examples of missed training that appeared also to be indicative of a lack of effective prioritization and allocation of resources.

2.6 Use of Industry Operating Experience

a. Inspection Scope

The inspectors reviewed the licensee's industry operating experience (OE) program and interviewed the OE coordinator and plant staff to assess the use of OE. The inspectors also reviewed the Excellence Plan action plan for improving the OE program (OP-10-010, "Operating Experience (OE) Improvement Plan").

b. Observations and Findings

The inspectors interviewed plant personnel to understand the use of OE, and noted that the various departments at Point Beach (maintenance, operations, chemistry, and radiation protection) had incorporated OE into their morning meeting schedules. The interviews included discussions of the transmittal of OE to the maintenance craft and engineering personnel.

Based on interviews and review of the Excellence Plan, the inspectors concluded that the OE program was not formalized in procedures, instead relying mainly on the efforts of the newly appointed OE coordinator. The Excellence Plan had provisions to develop procedures to ensure that the program would continue if personnel changes occur. The inspectors noted during the interviews that some of the personnel assigned as OE liaisons expressed a concern about the increase in workload and the ability to perform effectively as the number of tasks they were assigned increased.

2.7 Conclusions of the Corrective Action Program Phase of the IP 95003 Inspection

The inspectors concluded that the licensee's control systems for identifying, assessing, and correcting problems were adequate. However, implementation issues clearly contributed to the significant AFW findings and examples of poor implementation continued to exist despite licensee efforts to improve overall implementation. In particular, the inspectors concluded that several important corrective actions to prevent recurrence for the AFW findings had not been adequately implemented. These inadequately implemented corrective actions included the failure to adequately and consistently implement the Quality Review Team and the failure to conduct training specified as a result of the AFW findings. Several other actions were specified as corrective actions to prevent recurrence but the inspectors concluded that the actions themselves were not corrective actions and would not prevent recurrence. These included the CATPR specified to implement the fleet modification process for design verification and the CATPR to assign an issue manager. Overall, the inspectors determined that short-term corrective actions were adequate to prevent recurrence of the two specific AFW findings. However, weaknesses in the implementation of some long-term corrective actions indicated that continued attention was warranted to ensure that performance improvements related to the corrective actions could be sustained.

While the inspectors concluded that the corrective action program was adequate, there were weaknesses identified that could contribute to implementation problems. Examples of those weaknesses included a process that potentially categorized and analyzed issues at too low of a level and a weak trending process. Recent improvements to the corrective action program were good initiatives, but had not been formalized and, as a result, long-term improvement could not be assured.

The Excellence Plan addressed a number of significant problems at the plant, including some AFW-specific corrective actions and corrective action program problems. However, many of the actions were not completed and in fact, little work had begun. Examples included improvements in NOS effectiveness, AFW corrective actions, operating experience program, and design basis validation projects.

3. Emergency Preparedness

Cornerstone: Emergency Preparedness (95003.01)

During a baseline inspection in February 2002 (IR 50-266/02-04(DRS); 50-301/02-04(DRS)), the inspectors identified concerns regarding the adequacy of the licensee's critique of two performance issues during the biennial emergency preparedness exercise. In a letter dated September 12, 2002, the NRC issued a Final Significance Determination of White for a finding encompassing both issues. An additional problem was identified by the inspectors concerning the critique for the August 1, 2002, emergency preparedness drill (IR 50-266/02-10; 50-301/02-10).

In November 2002, the NRC began a supplemental inspection to review the licensee's root cause evaluation (RCE) for the White finding; however, the inspectors determined that the RCE (RCE000187) was inadequate. In response, the licensee revised the RCE. This revision was subsequently reviewed in March 2003 by the NRC and found to be acceptable (IR 50-266/02-14; 50-301/02-14(DRS)).

In early 2003 (IR 50-266/03-02; 50-301/03-02), the inspectors identified one finding of very low risk significance (Green) for inadequate configuration control and insufficient drawings and instructions provided to maintenance and operations personnel during an emergency notification telephone system battery charger failure and subsequent replacement activities.

Because of these recent findings and the turnover of upper management in the emergency preparedness/emergency planning (EP) group at Point Beach, it was decided to review EP as part of the IP 95003 supplemental inspection. For this effort, Attachment 95003.01, "Emergency Preparedness," was used. This Attachment had four objectives:

a. To gather information in support of the determination whether the licensee is capable of implementing adequate measures to protect the public health and safety in the event of a radiological emergency.

b. To verify that the EP program complies with applicable NRC regulations.

c. To verify that the licensee is complying with commitments made in the Emergency Plan.

d. To verify, to the extent practical, the absence of findings greater than White by determining the extent of condition of problems in the EP Cornerstone. (The risk significant planning standards (RSPSs) have the highest priority for inspection activities.)

These objectives were satisfied during the inspection through the review of the following six focus areas:

a. Correction of Weaknesses and Deficiencies

b. Emergency Response Organization (ERO) Readiness

c. Facilities and Equipment

d. Procedure Quality

e. ERO Performance

f. In-Depth Review of Risk Significant Planning Standards

3.1 Correction of Weaknesses and Deficiencies

a. Inspection Scope

The inspectors reviewed emergency preparedness/emergency planning (EP)-related CAPs, 10 CFR 50.54(t) audits, and outside and self-assessments for the last 2 years. All open EP CAPs and corrective actions related to the March 4, 2002, declaration of an Unusual Event and those associated with RCE 000194, “RCE 000187 Did Not Meet Standards to Close NRC Inspection,” were reviewed to determine if reasonable progress was being made toward completion. The inspectors reviewed a sample of minutes from meetings with local, state, and federal officials (offsite agencies), plan change concurrence documentation, and communication testing results to evaluate the adequacy of the interface with offsite agencies. The inspectors reviewed media training conducted for 2002 and 2003 against the requirements in the Emergency Plan in Section EP 8.0, paragraph 3.3.3, and Appendix E to 10 CFR Part 50. The inspectors reviewed all Letters of Agreement (LOAs) identified in Appendix D of the Emergency Plan to verify they supported Emergency Plan commitments. The inspectors reviewed Procedure NP 5.3.2, “Operating Experience (OE) Review Program,” a sample of “working copies” of ERO training lesson plans on topics associated with risk significant planning standards, and the ERO training program description to evaluate the effectiveness of the OE program. The inspectors reviewed medical response capabilities against the requirements in the Emergency Plan, and the LOAs for medical facility support. The inspectors interviewed EP management and staff and training personnel to determine their knowledge of the corrective action program and gain insights concerning implementation of the EP program. The inspectors also reviewed some past Emergency Preparedness Advisory Committee meeting minutes and attended one meeting during the inspection.

b. Observations and Findings

In general, self-assessments were adequate; however, in two instances, CAPs were not written for the improvement recommendations provided in the self-assessments nor were other means provided to address the recommendations.

The inspectors reviewed CAP032422, "A Formal Method For Scheduling Ingestion Exercises With the State Is Needed." Condition evaluation (CE) 011554 was initiated as a result of the CAP to determine if a formal method for scheduling ingestion exercises with the State of Wisconsin was needed. The CE determined that a formal method already existed in the conduct of a regional scheduling meeting hosted by the Region V office of the Federal Emergency Management Agency (FEMA). The CAP was closed as a result. The inspectors were concerned that the resolution of the CAP accepted reliance on an outside agency to ensure a licensee requirement (10 CFR Part 50, Appendix E, Section III.F.2 and 2.d; and Section 3, page 73 of NUREG-0654) was met.

The inspectors reviewed the licensee's evaluation of and associated corrective actions for a declaration of a Notice of Unusual Event (NOUE) on March 4, 2002, because of a low pressure propane gas leak near the protected area fence. The licensee determined that the classification of the event was untimely (31 minutes, compared to the limit of Appendix E of 10 CFR Part 50 of 15 minutes); however, this conclusion was not made until April 2003. This is a licensee-identified Green finding due to the untimely classification of a NOUE, and is described further in Section 5.

The inspectors identified that numerous opportunities to identify the untimely classification were missed by licensee evaluations of the NOUE. Each of the following licensee documents evaluated the timeliness of the classification and concluded that it was performed in a timely manner: (1) Nuclear Plant Memorandum (NPM) 2002-0016, "Report of Unusual Event Prepared Per NP 1.8.2"; (2) NPM 2002-0158, "Report of Unusual Event Prepared Per NP 1.8.2"; (3) CAP030381, written December 11, 2002, to evaluate if the March 4, 2002, Unusual Event declaration was timely; (4) ACE01112, written December 13, 2002, as part of CAP030381; (5) CA027674, initiated January 14, 2003, to revise NPM 2002-0158 to more accurately reflect actual events surrounding the classification and declaration of the Unusual Event; (6) CA027675, initiated January 14, 2003, to annotate station log entries for the Unusual Event such that no confusion existed about when certain events occurred; (7) RCE000187, "Failure of the Emergency Planning Critique Process to Identify Drill/Exercise Weaknesses," (this RCE identified the Unusual Event declaration as timely); and (8) RCE000194, "RCE 187 Did Not Meet Standards to Close NRC Inspection," (this RCE also identified the Unusual Event declaration as timely).

The EP staff initiated corrective action document [Other] OTH029034 on April 8, 2003, to compare the time-line of the Unusual Event with industry guidance in Nuclear Energy Institute (NEI) 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 2. It was this document that identified the classification was not timely. The performance indicator (PI) data was recalculated to indicate the drill and exercise performance (DEP) PI as having a failed classification opportunity. The inspectors determined that although the RCE determined that event start time for determination of timely classification was not well understood among both the operators and the facility EP staff, the licensee did not perform a thorough evaluation to determine if any crew performance deficiencies contributed to the late emergency classification.

The inspectors also noted that RCE000187 and the RCEs for the Unusual Event missed an opportunity to evaluate EAL 6.3.1.1 and its history. Recognition of the change from an earlier version that included the terminology "on-site" may have indicated that the EAL committed to was changed in error. The inspectors identified an apparent violation related to EAL changes, of which this EAL was one example of an EAL change that was made that decreased the effectiveness of the Emergency Plan. The apparent violation is discussed in Section 3.6.b.2 of this report.

3.2 ERO Readiness

a. Inspection Scope

The inspectors reviewed a sample of CAPs related to facility staffing/augmentation to determine adequacy of the corrective actions. The inspectors reviewed onshift staffing commitments in the Emergency Plan, Section 5, Figure 5-1, and Part 2.0, "Normal Plant Organization," to verify those commitments were met by shift staffing schedules. The inspectors reviewed procedure Operations Manual (OM) 3.1, Section 5.2, to determine the composition of normal shift staffing schedules. The inspectors reviewed ERO augmentation drill records against the response criteria for minimum staffing for emergency facility activation in the Emergency Plan. The inspectors reviewed data to determine if the ERO PI was properly evaluated, key responders were identified, drill credit was properly assessed, and equivalent positions defined against the standards in NEI 99-02, Revision 2. The inspectors also reviewed protective action recommendation (PAR) opportunities that contributed to the DEP PI from the 2nd quarter of 2001 through the 1st quarter of 2003 (8 quarters) to verify proper implementation of the NEI 99-02 guidance.

b. Observations and Findings

The inspectors identified two findings that were characterized as Non-Cited Violations. The first finding involved the licensee's failure to assign onshift staffing for an ERO function, which was determined to be of very low safety significance (Green). The second finding was the failure to accurately evaluate and report the ERO PI, a Severity Level IV violation.

b.1 Review of Onshift Staffing Requirements

The inspectors reviewed the onshift staffing requirements and normal plant organization as described in Section 5, Figure 5-1, and in Part 2.0, "Normal Plant Organization," of the Emergency Plan. The inspectors determined that the emergency plan required that, in addition to operations personnel, a qualified Radiation Protection Technologist, Radiation-Chemistry Technician, and Security Shift Commander be assigned to each shift. The inspectors reviewed actual onshift staffing of the Radiation Protection Technologist and Radiation-Chemistry Technician positions for Memorial Day weekend and the month of July 2003. All shifts during this time were staffed. Staffing of the Radiation Protection Technologist position was controlled in NP 4.2.28, “Health Physics Represented Personnel Assignment and Scheduling Policy.” Staffing of the Radiation-Chemistry position was scheduled via the Chemistry Work Plan. Although the current procedures staff these positions consistent with Emergency Plan requirements, neither procedure referenced those requirements. The inspectors identified the lack of reference to the Emergency Plan requirement as a potential vulnerability in the continued adequacy of NP 4.2.28 and the Chemistry Work Plan.

b.2 Failure To Assign Onshift Staff For ERO Function

Introduction: A Green, Non-Cited Violation associated with emergency planning standard 10 CFR 50.47(b)(2) was identified. Specifically, the licensee failed to assign onshift responsibilities for reading facility seismic monitors, thereby affecting the ability to timely classify certain seismic events.

Description: The EALs for operational basis and safe shutdown earthquakes (Alert EAL 6.1.1.2 and Site Area Emergency (SAE) EAL 6.1.1.3) required declaration of an emergency event when one of the four installed seismic monitors exceeded the event thresholds defined in the EAL. The monitors were located in various buildings, including the #3 warehouse, the Unit-1 façade, the drum preparation room, and between the vital switchgear room and the auxiliary feedwater tunnel. Currently, the warehouse seismic monitor (SEI-6211) was being calibrated in Sweden. Laptop computers were used to access and read the level of seismic activity sensed by the monitors. The inspectors identified that only Instrument and Control (I&C) technicians were trained to use the portable laptop computers to read the seismic monitors; however, I&C technicians were not assigned onshift at the facility, and were therefore not immediately available during off-normal working hours.

The I&C technician staffing was established in the 1984 Emergency Plan change as a 30-minute emergency responder, and allowed use of onshift auxiliary operators in lieu of onshift I&C technicians. At that time, the seismic monitors did not require the use of a laptop computer to retrieve the seismic data, and auxiliary operators could read the seismic monitors. Some time after 1984, the seismic monitors were replaced with the current monitors, which required use of a laptop computer to retrieve the seismic data. The licensee failed to identify that the change in seismic monitors would require that an I&C technician (or an appropriately trained auxiliary operator) be onshift to read the monitors after a seismic event to ensure a timely declaration of an emergency condition.

The inspectors concluded that during off-normal working hours, the licensee would not be able to assess in a timely manner the level of seismic activity using the monitors, which could delay the declaration of the associated Alert or Site Area Emergency.

Analysis: The failure to assign adequate staffing to perform an emergency response organization function is a performance deficiency that is more than minor because it is associated with a cornerstone attribute and affected the EP cornerstone objective (to ensure the adequate protection of the public health and safety). The finding involved the failure to ensure adequate staffing was assigned to be able to implement emergency action levels in a timely manner. When processed through the EP Significance Determination Process (SDP), the finding was found to have very low safety significance because it was only a degradation in the ERO onshift staffing, and therefore did not represent a planning standard function failure. The inspectors identified this finding while questioning the ability of control room personnel to receive necessary information to implement a sampling of EALs.

Enforcement: 10 CFR 50.54(q) provides in part that "A licensee authorized to possess and operate a nuclear power reactor shall follow and maintain in effect emergency plans which meet the standards in §50.47(b). . ." 10 CFR 50.47(b) requires that the onsite emergency response plans for nuclear power reactors meet each of 16 planning standards, of which, planning standard 2 states, in part: "On-shift facility responsibilities for emergency response are unambiguously defined, adequate staffing to provide initial facility accident response in key functional areas is maintained at all times..." Contrary to this, the licensee failed to maintain onshift staffing at all times to be able to read the facility seismic monitors. Failure to be able to read the monitors during or immediately following a seismic event would prevent timely implementation of the emergency plan and is a violation. Because the finding was determined to be of very low safety significance and was entered into the corrective action program as CAP034693, this violation is being treated as a Non-Cited Violation, consistent with Section VI.A of the NRC Enforcement Policy (NCV 50-266/03-07-01; 50-301/03-07-01).

b.3 Failure To Report Accurate ERO PI Information

Introduction: A Severity Level IV Non-Cited Violation of 10 CFR 50.9 was identified because the licensee failed to provide complete and accurate information to the NRC. Specifically, the inspectors identified that the ERO drill participation PI was not being properly evaluated by the licensee and that when the PI was recalculated with the complete and accurate data, the PI crossed the Green-to-White threshold for the 3rd quarter of 2001 (and subsequently returned to Green in the 4th quarter of 2001).

Description: The inspectors identified that an onshift communicator had not been designated in the Emergency Plan, and was not being tracked in the ERO drill participation PI. The onshift and Emergency Operations Facility (EOF) communicator positions were designated as key ERO positions in NEI 99-02, and must therefore be evaluated and tracked in the ERO drill participation PI.

Three onshift positions were trained to complete the emergency notification form: Shift Manager, Operations Supervisor, and Shift Technical Advisor. None of these positions were being tracked in the ERO drill participation PI. The EOF emergency notification procedure, emergency plan implementing procedure (EPIP) 2.1, "Notifications - ERO, State and Counties, and NRC," Revision 26, directed the Emergency Director to perform the notification task or delegate that function, but did not identify which position in the EOF was qualified to perform that function. Currently, the EOF communicator, EOF Manager, and the Emergency Director were the three EOF positions trained to complete the emergency notification form. Only the EOF communicator was being tracked for the ERO drill participation PI as a communicator.

The licensee evaluated the condition and identified 23 qualified onshift communicators that should have been tracked and reported in the ERO drill participation PI. After reevaluating the PI, the indicator would have been White (<80 percent) for the third quarter of 2001, then Green for all subsequent quarters, including the current quarter.

The inspectors also noted that the onshift Security Commander was designated in EPIP 2.1 as an onshift communicator, but that position was not trained to complete the emergency notification form. The inspectors concluded that this designation of the Security Commander as an onshift communicator indicated a further misunderstanding of the guidance in NEI 99-02.

Analysis: The failure to accurately track and report the ERO drill participation PI was a performance deficiency that was more than minor because it was associated with a cornerstone attribute and affected the EP cornerstone objective (to ensure the adequate protection of the public health and safety). The finding involved the failure to accurately report PI data, which, if accurately calculated and reported, would have caused the NRC to perform additional inspection activities in the fourth quarter of 2001. This issue was not suited for SDP analysis and was evaluated with the traditional enforcement process.

Enforcement: 10 CFR 50.9 requires in part that "Information provided to the Commission by ... a licensee ... shall be complete and accurate in all material respects." Contrary to this, the licensee failed to report in the 3rd quarter of 2001 that the ERO drill participation PI crossed the significance threshold to White. The NRC considered errors in PI data reporting which cause the PI to cross the Green-to-White threshold to be more than minor because they have the potential for impacting the NRC's ability to perform its regulatory function, in this case, to have performed a supplemental inspection. In the traditional enforcement process, this violation is classified as a Severity Level IV violation, and because it was entered into the licensee's corrective action program (as CAP034650), it is being treated as a Non-Cited Violation, consistent with Section VI.A of the NRC Enforcement Policy (NCV 50-266/03-07-02; 50-301/03-07-02). The licensee has since submitted the complete and accurate PI data to the NRC.

3.3 Facilities and Equipment

a. Inspection Scope

The inspectors reviewed recent CAPs related to emergency facilities and equipment. The inspectors reviewed the emergency alert siren design basis in the FEMA-approved Alert and Notification System (ANS) design report. The inspectors reviewed the designation and capabilities of offsite assembly areas to meet decontamination needs, status of radiation monitoring equipment, and ability to handle evacuation vehicles against the criteria of the Emergency Plan. The inspectors toured the Technical Support Center (TSC) and EOF to determine the adequacy of those facilities to meet selected design standards in NUREG-0696, "Functional Criteria for Emergency Response Facilities," February 1981.

The inspectors reviewed Emergency Plan Maintenance Procedure (EPMP) 5.0, "Post-TMI Meteorological Monitoring Program Design, Operation, and Maintenance," a 2003 self-assessment of the plant's meteorological monitoring program, a sample of monitoring system calibration records, and a sample of corrective action and other program records against the program requirements of Section 7 of the Emergency Plan. The inspectors reviewed a 1982 edition of the meteorological monitoring system descriptive manual and observed a periodic surveillance of both onsite monitoring stations. The inspectors observed an August 5 meeting of the monitoring system upgrade project team that involved representatives of several plant departments, including I&C, engineering, procurement, and EP. The inspectors also discussed the meteorological monitoring program with several EP staff members. The inspectors also reviewed relevant portions of the Emergency Plan, a 2003 "White Paper on Configuration Management" licensee document on equipment configuration management at the Site Boundary Control Center (SBCC) that housed the onsite EOF and the Offsite Radiation Protection Facility. The inspectors reviewed a sample of emergency facility-related corrective action program documents, and reviewed a sample of heating, ventilation, filtration, and air conditioning equipment maintenance records to determine operability of the emergency facilities against the standard in NUREG-0696 and the requirements and commitments in the Emergency Plan.

b. <u>Observations and Findings</u>

The inspectors reviewed meeting minutes of the Plant Health Committee from May 9, 2003. The minutes indicated that meteorological monitoring equipment issues included shortages of spare sensors and other electronic components, degrading wiring, and recognition of the potential adverse impact on the capability to perform offsite dose projections using data from this monitoring system. The meeting minutes also described the status of the meteorological monitoring system as a major issue and a vulnerability, and that upgrading this system was one of the plant's top three priorities.

Following the Plant Health Committee meeting discussions, the licensee established a multi-disciplinary team for a meteorological monitoring system upgrade project. The inspectors reviewed meeting minutes from the project team's initial meeting of July 29, 2003, and attended the second meeting on August 5. Discussion topics included worker safety concerns, the obsolescence and long-term reliability of the instrumentation, and availability of spare electrical components for about another year of service. The project team decided to develop a range of monitoring system upgrade options to present to senior management for consideration by early September 2003.

The inspectors concluded that appropriate attention was being applied to currently identified material condition and aging concerns for the emergency facilities and the meteorological monitoring equipment. As part of Revision 2 of the Excellence Plan, scheduled to be effective in mid- to late-January 2004, the licensee developed action plan OP-09-005, "Control/Maintenance of EP Required Equipment," to address long-term EP equipment reliability.

The inspectors reviewed the actions that had been taken for Unresolved Item (URI) 50-266/03-02-02; 50-301/03-02-02. The URI encompassed the following concerns: (1) the licensee's 50.59 process did not refer EP issues to 10 CFR 50.54(q) for further screening; (2) there were insufficient instructions, procedures, or drawings to help technicians assess communications equipment problems in emergency response facilities; (3) equipment in the EOF or Joint Public Information Center (JPIC) could be replaced by non-licensee personnel without the licensee's knowledge; and (4) the ability to remotely monitor Emergency Notification System (ENS) operability was lost since January 17, 2003.

The inspectors determined that the fourth concern was not significant given that the licensee maintains an onsite telephone line having a long distance calling capability. To address the third concern, the inspectors toured the onsite EOF and discussed the URI with licensee staff. The inspectors also reviewed the minutes of a Plant Health Committee meeting conducted on August 1, 2003. Several corrective actions to address EOF configuration management concerns were initiated, and many of the short-term corrective actions had not yet been completed. For example, a corrective action had not yet been completed to install postings at the EOF to warn non-licensee equipment service providers not to work on EOF equipment without prior coordination with the licensee's work control center. The inspectors reviewed the licensee's "White Paper on Configuration Management." The inspectors observed that the white paper did not address potential equipment and material condition concerns at the JPIC.

During interviews with members of the EP staff, the inspectors noted that one of the four station seismic monitors used for assessment in the category 6.1 EALs, "Natural Destructive Phenomena," had been sent to Sweden for calibration. The inspectors determined that the unavailability of the monitor was not evaluated for the affect on the Emergency Plan or the ability to implement the associated EALs, and no compensatory measures were put in place. The inspectors determined that loss of one seismic monitor would not prevent implementation of the associated EALs, but did represent a degradation in the reliability of the seismic monitoring system. Emergency Plan Section 7, Table 7-1, identified the seismic monitoring equipment as "4 strong motion accelerographs," used for assessment provided in 4 plant locations. The inspectors questioned the EP staff on control of equipment important to EP functions. The staff indicated that corrective action CA029777, "Create A Procedure To Follow When EP-Related Equipment Is OOS," May 14, 2003, had been written to address the lack of a program to identify EP-related equipment and the need to contact the EP staff when that equipment was affected. An appropriate program had been partially drafted at the end of this inspection.

Based on the status of several open CAPs associated with the URI, future NRC inspection will be required to gather additional information to assess the adequacy of licensee actions related to URI 50-266/03-02-02; 50-301/03-02-02.

The inspectors identified an inconsistency between the Emergency Plan and the FEMA-approved ANS Design Report. Tone alert radio pagers (Section E.6.2.3 of the design report) were noted as being part of the primary alert notification system, but were not currently referenced in the Emergency Plan. The inspectors determined that only one tone alert pager was currently in use, south of the plant at the Point Beach State Forest park, and procedures were in place to ensure it could perform its notification function. The inspectors noted that Appendix V of the design report was referred to in context with the park emergency procedures, but Appendix V no longer existed in the design report. All other areas of the emergency planning zone (EPZ) were notified through emergency sirens, and tone alert radios were not required.

The inspectors reviewed the designation of and procedures associated with the offsite assembly areas for exclusion area evacuation. Emergency Plan Section 6.0, paragraph 5.1.1.d.2(d) and (e), stated that individuals were to proceed to a designated offsite assembly area when a plant and exclusion area assembly, release, or evacuation was ordered. These designated offsite assembly areas were the SBCC, the Two Creeks Town Hall, and the Two Rivers National Guard Armory, as identified in Table 6-2 of the Emergency Plan. The Emergency Plan contained letters of agreement with two locations, Two Creeks Town Hall and the Two Rivers National Guard Armory. The SBCC was a licensee-controlled building located within the owner-controlled area and, as such, did not require a LOA. The inspectors reviewed EPIP 6.1, "Assembly and Accountability, Release and Evacuation of Personnel," Revision 24, and determined that although it provided direction on performance of radiological monitoring and decontamination at the SBCC, it did not provide specific guidance for the other two offsite assembly areas. In addition, the inspectors noted that EPIP 6.1 stated that an offsite assembly area could be located "along the evacuation route, if appropriate." However, the procedure did not provide direction on how this location was to be determined or established to provide radiological monitoring and decontamination efforts. The inspectors determined that these procedure weaknesses could potentially impact the ability to efficiently establish an offsite assembly area.

The inspectors concluded that the licensee had identified and was pursuing correction of emergency facility and equipment problems, and that the licensee had identified where some significant challenges remained in this area. The inspectors also concluded that development and implementation of an effective procedure to identify and track plant equipment maintenance that could affect emergency preparedness was essential to ensure that problems, such as the lack of control of seismic monitor and emergency facility maintenance, were not repeated. In addition, the licensee's development and successful implementation of an Excellence Plan action plan item to address long-term EP equipment reliability could result in performance improvements in this area.

3.4 Procedure Quality

a. Inspection Scope

The inspectors reviewed the administrative procedure for the corrective action program (NP 5.3.1) to determine the threshold for addressing EP issues in the corrective action program. The inspectors sampled recent Emergency Plan changes to determine if those changes were correctly translated into appropriate procedures. The inspectors reviewed a sample of EPIPs to determine consistency with Emergency Plan requirements. The inspectors also reviewed the Emergency Plan against the requirements in 10 CFR Part 50, Appendix E, "Emergency Planning and Preparedness for Production and Utilization Facilities." The inspectors reviewed public information brochures provided by the licensee to members of the public living and visiting in the EPZ, and the Emergency Alert Pre-Scripted Message Manual For Point Beach Nuclear Power Plant, December 26, 2001, against the requirements in 10 CFR 50.47(b).

b. Observations and Findings

The inspectors did not identify any significant procedure quality concerns. In general, when emergency preparedness problems were identified, they were appropriately characterized in the corrective action system. The inspectors concluded that the most significant challenge in this area was implementation of a procedure to control emergency preparedness related equipment maintenance, which is discussed in this section and Section 3.3 of this report. The inspectors identified one minor violation while comparing portions of the Emergency Plan against the requirements of 10 CFR Part 50, Appendix E.

10 CFR Part 50, Appendix E, Section IV.B, "Assessment Actions," states, in part, that "... emergency action levels shall be discussed and agreed on by the applicant and State and local government authorities ... ." The inspectors determined that seven EAL changes had been made since 1999, but that records of State and local governmental authority review were unavailable for changes made on February 6, July 7, and November 15, 2002. Also, the inspectors determined that the licensee did not have a system in place to prompt a review of EAL changes during other than the end of year annual review. Because reviews of the EAL changes were conducted annually, and monthly meetings with local authorities routinely discussed issues, such as EAL changes, prior to the scheduled annual review, this violation of Section IV.B was considered a violation of minor significance, not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy.

The inspectors reviewed CAP030938, FT-3299B, "DAVS Isokinetic Sampler Flow Channel Failed High," and CAP032427, "U2 Condenser Air Removal Oscillations Affect On Primary To Secondary Leak Detection." The subject equipment in both of these CAPs provided indication for emergency assessment/classification; however, neither CAP assessed the impact of the equipment failures on emergency classification capability. During a review of capability to implement EALs, the inspectors also identified that although the four seismic monitors used at the facility were identified as EP assessment equipment, the laptop computers that were necessary to obtain the seismic readings from the monitors were not controlled equipment and the EP staff was not procedurally informed when the equipment was taken out of service. The licensee had identified this generic weakness and wrote corrective action CA029777, "Create A Procedure To Follow When EP-Related Equipment Is OOS," May 14, 2003. The inspectors questioned the licensee on the status of completion of the corrective action. The licensee stated that a matrix of EP-related equipment had been developed, but other procedural changes to implement the matrix had not been completed. The inspectors determined that reasonable progress had been made to address CA029777.

3.5 ERO Performance

a. Inspection Scope

The inspectors observed two crews during licensed operator requalification (LOR) simulator scenario evaluations on July 28 and August 4, 2003. The inspectors observed one limited scope emergency exercise, which involved all emergency response facilities, except the JPIC, and simulated offsite and NRC participation. The inspectors evaluated crew performance during the drill, and compared that evaluation with the evaluation performed by facility drill controllers and evaluators. The inspectors evaluated the crews' performance against facility operating, abnormal, and emergency procedures, as well as the Emergency Plan and the EPIPs. The inspectors evaluated the ERO training program against 10 CFR 50.47(b)(15) and (16), and 10 CFR Part 50, Appendix E, Section IV.F. The inspectors compared a sample of EP-related lesson plans with the Emergency Plan, EPIPs, and the regulations. The inspectors reviewed a sample of CAPs related to EP training. The inspectors interviewed training and EP staff to evaluate management support of ERO training. The inspectors reviewed the EP training programs against the requirements of the Emergency Plan.

The inspectors reviewed Revision 45 of Chapter 8 of the licensee's Emergency Plan, the 1984 revision of this Chapter, the Training Department's August 1, 2003, revision of the ERO training program, and a sample of "master copy" and "working copy" ERO lesson plans.

The inspectors reviewed a random sample of 25 ERO members' computerized training records in order to determine whether these persons were considered to be currently trained in accordance with the EP training program's criteria. The inspectors reviewed self-contained breathing apparatus (SCBA) qualification records of a sample of 70 ERO members. The inspectors reviewed the most recent medical response drill involving simulated contaminated, injured victim(s), which was conducted in August 2002, and the related corrective action program documents. The inspectors interviewed the lead EP training instructor and reviewed relevant training records of a sample of ERO members to determine if their training was current.

b. Observations and Findings

b.1 Training

The inspectors identified one finding that was characterized as a Non-Cited Violation of very low safety significance (Green). The finding was a failure to establish a training program for the emergency planning department staff.

Introduction: A Green, Non-Cited Violation associated with planning standard 10 CFR 50.47(b)(16) was identified. Specifically, the licensee failed to develop and implement an EP staff training program to ensure that planners were properly trained.

Description: In NRC supplemental IR 50-266/02-14(DRS); 50-301/02-14(DRS), the NRC identified that a formal training program had not been developed to ensure that emergency planners were properly trained. The licensee wrote CAP029492, which was closed after development of a training program in April, 2003. Subsequently, in July 2003, the recently appointed EP manager evaluated the training program as inadequate and canceled the training program procedure (as documented in CAP033979). After completion of the onsite portion of this inspection, Section 5.0, “EP Staff Training,” was developed (as part of CA032011) and added to Procedure EPMP 3.2, “Offsite Personnel and Emergency Preparedness Staff Training,” Revision 10, on August 27, 2003.

Analysis: The failure to develop and implement an EP staff training program was a performance deficiency that was more than minor because it was associated with a cornerstone attribute and affected the EP cornerstone objective (to ensure the adequate protection of the public health and safety). The finding involved the failure to ensure that the EP staff was properly trained. When processed through the EP SDP, the finding had very low safety significance because lack of a staff training program presented a potential degrading condition for the level of qualification and proficiency of the EP staff, but did not represent a failure of the planning standard function. The inspectors identified this finding while interviewing the EP staff and reviewing corrective actions associated with IR 50-266/02-14(DRS); 50-301/02-14(DRS).

Enforcement: 10 CFR 50.54(q) provides in part that “A licensee authorized to possess and operate a nuclear power reactor shall follow and maintain in effect emergency plans which meet the standards in §50.47(b). . .” 10 CFR 50.47(b) requires that the onsite emergency response plans for nuclear power reactors must meet each of 16 planning standards, of which, planning standard 16 states, in part: “...[Emergency] planners are properly trained.” The Point Beach Emergency Plan, Section 8.0, paragraph 3.1.4, states, in part: “EP staff training required as appropriate.” Contrary to this, the licensee failed to develop and implement an emergency planning staff training program, and therefore could not ensure that the planners were properly trained. Because the finding was determined to be of very low safety significance and was entered into the licensee’s corrective action program as CAP033979, this violation is being treated as a Non-Cited Violation, consistent with Section VI.A of the NRC Enforcement Policy (NCV 50-266/03-07-03; 50-301/03-07-03).

The inspectors identified an inconsistency between the Emergency Plan and EP-TP, (EP Training Program), on requalification training requirements. EP-TP stated that an ERO member could acceptably complete all requalification training requirements by participating in an EP drill or exercise, but the Emergency Plan, Section 8, stated that requalification training for the ERO shall be a combination of drills and exercises, classroom and reading training relevant to the ERO position assignment. The inspectors determined that the inconsistency represented a potential vulnerability to keeping ERO members training up-to-date on changes to the Emergency Plan, the EPIPs, associated regulatory guidance, and relevant industry OE.

During the evaluation of the LOR drills, the licensee determined that interpretation of the Alert EAL for failure of the reactor protection system was inconsistent among the operating shift crews. The licensee entered the observation in the corrective action process as CAPs 034364, 034387, and 034547 and the Plant Manager issued a memorandum to all operators to clarify the EAL. The inspectors independently evaluated the LOR scenarios, and agreed with the licensee’s conclusions and corrective actions.

b.2 Exercise Performance

The inspectors observed a limited-scope emergency exercise, August 14, 2003, which involved use of all the licensee emergency facilities, and simulation of offsite facilities and governmental agencies. The simulated emergency involved an escalation of emergency conditions through each of the four emergency classification levels, beginning with a NOUE due to abnormally high activity in the reactor coolant. Next, an Alert was required due to a large increase in reactor coolant activity, then a Site Area Emergency was required due to a reactor coolant leak into the containment. Finally, a General Emergency was required due to a large break in the reactor coolant system and a sudden failure of the containment. The simulated release of radioactivity to the environment then required evaluation and issuance of protective action recommendations to local government officials for the protection of the public near the facility.

The inspectors independently assessed the onshift crew response in the simulator control room, as well as the performance of the augmenting emergency response organization in the EOF, TSC, and Operations Support Center (OSC). The inspectors then compared that assessment to the licensee's self-critique of its performance which was presented to the inspectors on August 15, 2003. The licensee's assessment of performance, related to the emergency planning standards in 10 CFR 50.47(b), was consistent with the inspectors' assessment.

Overall, performance by the onshift and the augmenting emergency responders was adequate and demonstrated successful implementation of the Emergency Plan.

The licensee identified several areas requiring corrective action during the critique and entered the observations in the corrective action program. The inspectors determined that none of the performance deficiencies identified were significant and did not impact the ability of the licensee to adequately respond to an emergency. The inspectors did not identify any additional performance deficiencies and concluded that the licensee's critique of the exercise was thorough and self-critical. In the control room simulator, proper actions were taken to mitigate the events and the associated classifications and notifications to offsite agencies were performed within required time limits. Communications between the control room, OSC, TSC, and EOF were adequate. Good command and control was observed in each of the emergency facilities, and emergency classifications and notifications were completed successfully.

The inspectors observed the post-exercise self-critiques in each of the emergency facilities. Each of the critiques was self-critical and focused on performance issues. In the EOF, the inspectors observed a health physics technician question the appropriateness of the protective action recommendation following the General Emergency declaration. This emergency responder stated that due to the very short duration of the release, a shelter protective action recommendation may have been more appropriate than an evacuation recommendation. This comment was acknowledged by the EP staff leading the critique, but it was also stated that the current procedures did not allow a shelter recommendation. The inspectors concluded that the protective action recommendation was consistent with the requirements in the Point Beach Emergency Plan. The adequacy of the Emergency Plan and procedures in not allowing a shelter recommendation was identified as an unresolved item and is discussed in Section 3.6 of this report.

Overall, the inspectors concluded that the exercise was a successful demonstration of the licensee's ability to implement the Emergency Plan to protect public health and the environment.

3.6 <u>In-Depth Review of RSPSs</u>

a. <u>Inspection Scope</u>

The inspectors performed a detailed review of the licensee's compliance with 10 CFR 50.47(b)(4) and (10). The inspectors reviewed NUREG-0654/FEMA-REP-1, Revision 1, Section II.D., "Planning Standards and Evaluation Criteria-Emergency Classification System," as informing criteria to determine compliance with the planning standard. The inspectors reviewed EPIP 1.2, "Emergency Classification," Revisions 20-33, and Appendix B to the Emergency Plan, and compared the current EALs against the criteria in NUREG-0654, Revision 1, Appendix 1. The inspectors also reviewed NUMARC/NESP-007, "Methodology for Development for Emergency Actions Levels," Revision 2, and Regulatory Guide 1.101, "Emergency Planning and Preparedness for Nuclear Power Plants," Revision 3, as informing guidance for review of the EALs. The inspectors conducted a facility and simulator control room walkdown to verify that indications required for implementation of a sample of 17 EALs were available in a timely manner to the control room staff. The inspectors also reviewed a sample of CAPs related to event classification.

b. <u>Observations and Findings</u>

The inspectors identified three findings. The first finding was characterized as an unresolved item (URI) related to the failure to establish a range of PARs associated with RSPS 10. The second finding was characterized as an apparent violation (AV) involving a failure to maintain a standard scheme of EALs, associated with RSPS 4. The third finding was characterized as a Non-Cited Violation of very low safety significance (Green) involving a failure to maintain the ability to implement a Notification of Unusual Event (NOUE) EAL, also related to RSPS 4.

b.1 <u>Failure to Establish a Range of Protective Action Recommendations</u>

<u>Introduction</u>: A finding associated with emergency planning standard 10 CFR 50.47(b)(10) was identified. Specifically, the licensee failed to ensure that a range of PARs was established for state and local governmental authorities. This finding is characterized as a URI pending further regulatory review of the potential generic aspects of this finding, including the review of the current regulations and regulatory guidance for providing PARs.

<u>Description</u>: The inspectors reviewed the Emergency Plan and noted a statement in Chapter 6.0, "Emergency Measures," Section 5.1.2.a.5 (a): "Although the State of Wisconsin and the counties could implement sheltering, and because sheltering has different meanings for NRC and FEMA, Point Beach Nuclear Plant will only recommend

evacuation as a protective action for the public." The inspectors noted that this statement was inconsistent with federal guidance issued in a combined FEMA and NRC document, NUREG-0654/FEMA-REP-1, Revision 1, Supplement 3, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants." The subtitle of this guidance document was "Criteria for Protective Action Recommendations for Severe Accidents." Section II of NUREG-0654, Supplement 3 stated, in part, "The guidance emphasizes that the preferred initial action to protect the public from a severe reactor accident is to evacuate immediately about 2 miles in all directions from the plant and about 5 miles downwind from the plant. In addition, shelter may also be the appropriate protective action for controlled releases of radioactive material from the containment if there is assurance that the release is short term (puff release) and the area near the plant cannot be evacuated before the plume arrives."

The inspectors reviewed facility emergency notification forms, notification procedures, and the emergency director checklists. None of the documents reviewed contained guidance nor supported issuing other than an evacuation recommendation to the offsite government authorities. The inspectors also observed a limited scope emergency exercise during which a large, short duration initial release of radioactivity was simulated, followed by an almost complete cessation of the release. During the critique of the exercise, the individual who had acted as the emergency director in the EOF stated that he had not made a shelter recommendation because it would have violated the Emergency Plan.

The inspectors reviewed the change package for Revision 5 to EPIP 1.1.2, "Plant Operations Manager, General Emergency - Protective Actions"; Revision 17 to EPIP 9.3, "Protective Action Evaluation"; and Revision 30 to the Emergency Plan. These changes were made in January 1994 to ensure consistency of these procedures with the licensee's interpretation of the U.S. Environmental Protection Agency guidance in EPA-400-R-92-001, "Manual of Protective Action Guides And Protective Actions For Nuclear Incidents," May 1992. Notification forms that were to be filled out according to EPIP 2.1, "Notifications - ERO, State and Counties, and NRC," were also revised to remove sheltering as a licensee recommendation. Revision 17 of EPIP 9.3, "Protective Action Evaluation," changed the minimum protective action for a general emergency from sheltering to evacuation. The inspectors noted that Revision 30 of the Emergency Plan discussed sheltering as an option, but the supporting EPIPs as changed in January 1994 did not support issuing a shelter recommendation. The inspectors reviewed NRC correspondence and determined that no NRC review of Revision 30 to the Emergency Plan was documented.

The inspectors reviewed Revision 33 to the Emergency Plan. This revision, made in January 1997, incorporated guidance in NUREG-0654, Supplement 3, by adding Figure 1, "Severe Core Damage or Loss of Control of Facility, Public Protective Actions," as Table 4-1 in the Emergency Plan. With this revision to the Emergency Plan, all discussion of sheltering as a PAR option was removed. NRC Region III letter dated March 27, 1997, stated, in part, "In late January, 1997, Region III received individually numbered revisions to the Point Beach Nuclear Plant's emergency plan, which were dated January, 1997. Our initial review of these changes indicates them to be in accordance with 10 CFR 50.54(q). Implementation of these changes will be subject to inspection to confirm that they do not decrease the effectiveness of your emergency plan."

The inspectors also reviewed Revision 35 to the Emergency Plan. This revision, dated October 28, 1998, added the current statement that only an evacuation PAR would be given to the state and local governmental agencies. This plan change was submitted to the Region III office as required, but was not submitted for preapproval. NRC IR 50-266/98020(DRS); 50-301/98020(DRS), which was an evaluated exercise report, stated, in part, in Section P3, that "The inspectors reviewed a sample of ... emergency plan sections, including those related to the October 28, 1998, Emergency Plan Revision." The observations and findings section does not address any conclusions specifically for the Emergency Plan revisions. This scope statement in the 1998 report was the most specific reference to some level of review of the October 1998 changes, but did not specifically state that the change was reviewed for a decrease in effectiveness. NRC Region III letter dated March 26, 1999, stated, in part, "In November 1998, Region III received various changes to portions of the Point Beach Nuclear Plant Emergency Plan. Our initial review of these changes will be subject to inspection to confirm that they have not decreased the effectiveness of your Emergency Plan." The inspectors determined that review of Revision 35 to the Emergency Plan had been documented, but approval of the changes had not been given in the inspection report nor the March 26, 1999, letter. During the 95003 inspection, the inspectors determined that the change constituted a decrease in effectiveness of the plan and should have been submitted to NRC for review and pre-approval.

Analysis: The failure to ensure that a range of PARs had been developed to protect the public is a performance deficiency that is more than minor because it is associated with a cornerstone attribute and affected the EP cornerstone objective (to ensure the adequate protection of the public health and safety.) The finding involved the failure to ensure that a range of PARs was developed and would be given to state and local government authorities as appropriate for the associated emergency conditions. When processed through the EP SDP, the finding was found to have a potential significance of greater than very low significance because it represented a potential failure of the RSPS 10 function of providing a range of PARs. The inspectors identified this finding while reviewing the Emergency Plan and EPIPs. The licensee entered the finding in their corrective action process as CAP034785.

Enforcement: 10 CFR 50.54(q) provides, in part, that a licensee authorized to possess and operate a nuclear power reactor follow and maintain in effect emergency plans which meet the standards in §50.47(b). The nuclear power reactor licensee may make changes to the plans without NRC approval only if the changes do not decrease the effectiveness of the plans and the plans, as changed, continue to meet the standards of §50.47(b). Proposed changes that decrease the effectiveness of the approved emergency plans may not be implemented without application to and approval by the NRC.

10 CFR 50.47(b) requires that the onsite emergency response plans for nuclear power reactors meet each of 16 planning standards, of which, planning standard 10 states, in part, that a range of protective actions be developed for the plume exposure pathway EPZ for the public, and in developing this range of actions, consideration be given to

evacuation and sheltering and that guidelines for the choice of protective actions also be developed and put in place. Contrary to this, the Point Beach Emergency Plan, Chapter 6.0, “Emergency Measures,” Section 5.1.2.a.5 (a), states, in part, “Although the State of Wisconsin and the counties could implement sheltering, and because sheltering has different meanings for NRC and FEMA, Point Beach Nuclear Plant will only recommend evacuation as a protective action for the public.” As a result, the facility has not developed a range of PARs. The finding was determined to be an unresolved item pending further regulatory review of the potential generic aspects of this issue, including a review of past correspondence and generic communications with the industry regarding PARs (URI 50-266/03-07-04; 50-301/03-07-04).

b.2 Failure to Maintain a Standard Scheme of Emergency Action Levels

Introduction: A finding and apparent violation of 10 CFR 50.54(q), associated with RSPS 4 of 10 CFR 50.47(b), was identified. Specifically, the licensee failed to maintain a standard scheme of EALs, as defined in Regulatory Guide 1.101, “Emergency Planning and Preparedness for Nuclear Power Plants.”

Description: The inspectors identified a significant deviation in the EAL scheme used at Point Beach from the version approved in 1984 via a Safety Evaluation Report (SER) after NRC review of a revision of the Emergency Plan. As discussed in Revision 4 of Regulatory Guide 1.101, the EAL schemes in the following documents were acceptable for meeting 10 CFR 50.47(b)(4) and 10 CFR Part 50, Appendix E requirements: NUREG-0654/FEMA-REP-1; NUMARC NESP-007; and the most recently approved, Nuclear Energy Institute (NEI) 99-01, “Methodology for Development of Emergency Action Levels,” Revision 4, January 2003.

Chapter 4 of the Emergency Plan (Revision 38, dated February 6, 2002) stated that the emergency classification system was based on NUREG-0654, Revision 1, Appendix 1. In 1984, NRC reviewed revisions of the Emergency Plan using the criteria of the 16 emergency planning standards as stated in NUREG-0654. The NRC’s conclusions were transmitted to the licensee as SER 50-266/83-25 and 50-301/83-23, dated February 2, 1984. The licensee’s emergency classification procedure, EPIP 1.2, Revision 39, and the Emergency Plan, Appendix B, contained the EALs for Point Beach.

The inspectors compared EPIP 1.2, “Emergency Classification,” Revision 39, to NUREG-0654 and determined that the Point Beach EAL scheme was missing the following initiating conditions that were in NUREG 0654: NOUE 1, 4, 6, 8, and 9; Alerts 2, 3, and 9; Site Area Emergencies (SAEs) 1, 2, 8, 10, 13b, and 13c; and General Emergencies (GEs) 1a, 5a, 5c, 5d, and e. The inspectors also noted that the EAL scheme used a fission product barrier table that was not consistent with NUMARC-007 in that the "barrier challenged" column was not used to escalate the classification at the SAE level.

The inspectors also compared the current EALs in EPIP 1.2, Revision 39, to the 1984 version of EALs. The inspectors determined that there were 7 EALs missing in the current version. The current format of the EALs was significantly changed on December 29, 1999, with Revision 33 to EPIP 1.2, when the “Fission Product Barrier” table was incorporated. Change documents also removed 3 specific EALs that were derived from the FSAR. Another EAL was reduced from an Alert to an NOUE.

The inspectors determined that many of the changes were in agreement with changes that would be found acceptable as described in NRC guidance in EPPOS-1, "Emergency Preparedness Position (EPPOS) On Acceptable Deviations From Appendix 1 of NUREG-0654 Based Upon The Staff's Regulatory Analysis of NUMARC/NESP-007, 'Methodology For Development of Emergency Action Levels'"; however, a number of other changes, as summarized below, should have been submitted to NRC for prior approval. Regulatory Guide 1.101, Section C, indicated that using portions of both EAL methodologies was not acceptable. EPPOS-1 allowed use of the basis of the NUMARC scheme to enhance and clarify some site-specific EALs developed from NUREG 0654; however, it stated that the scheme must remain internally consistent.

The inspectors identified eight EALs that had been changed from the 1984-approved EAL scheme that should have been submitted to the NRC's Office of Nuclear Reactor Regulation for review and approval prior to implementation. The inspectors determined that the eight EAL changes, discussed below, decreased the effectiveness of the Emergency Plan in that emergency conditions that would have resulted in classifications at the GE, Alert, and NOUE levels would result in a lesser classification under the licensee's current EAL scheme.

> <u>GENERAL EMERGENCY</u>: EAL GE-1, as approved in 1984, required, in part, the declaration of a GE if a field dose rate corresponding to a 5 Rem committed dose equivalent to the thyroid (for 1 hour of inhalation) was measured. With the revision of this EAL on October 28, 1998, in Revision 32 to EPIP 1.2, the current EAL wording does not require a GE declaration directly from a field dose rate measurement corresponding to a 5 Rem committed dose equivalent to the thyroid (for 1 hour of inhalation). This revision resulted in a less conservative criterion for a GE declaration.
>
> EAL GE-5(b), as approved in 1984, required, in part, the declaration of a GE for a transient causing loss of all feed/condensate and all AFW for greater than 1 hour. With the revision of this EAL on December 29, 1999, in Revision 33 to EPIP 1.2, the current EAL required a loss of vital alternating current for greater than 15 minutes, and replaced the greater than 1 hour loss of all feed/condensate requirement with steam generator level and AFW flow criteria that would indicate a significant loss of feed. The addition of the loss of vital electrical power criterion is a more restrictive condition.
>
> <u>ALERT</u>: EALs A-18a and A-18b involved "other hazards being experienced or projected." The first EAL involved an aircraft crash in the protected area, and the second involved a missile impact from any source by visual observation. Both EALs had a more restrictive condition added to say that the hazard was "affecting operability of one (1) train of a safety system."

These two EALs were revised on December 29, 1999, in Revision 33 to EPIP 1.2, which was also part of Revision 14 to the Emergency Plan Index.

NOUE: EALs UE-14c and UE-14d, involved “other hazards,” including explosion and toxic/flammable gas release. While the original EALs included the owner controlled area, the EALs were changed to exclude areas of the site outside the protected area, resulting in a more restrictive condition.

EAL UE-13 involved a tornado sighting. While the original EAL was applicable if a tornado was visible from the site, the EAL was changed to make it applicable only if a tornado was within the protected area or switchyard, resulting in a more restrictive condition.

The EAL scheme approved by the NRC in 1984 included an NOUE (Category 18a) for uncontrolled control rod withdrawal. This EAL was removed from the EAL scheme with an explanation that an uncontrolled rod withdrawal event was encompassed in the Alert EAL for a Reactor Protection System (RPS) failure. However, the inspectors concluded that this explanation was incorrect, since EALs for RPS failure did not address an uncontrolled rod withdrawal. The inspectors concluded that there were no EALs in the current EAL scheme for an uncontrolled control rod withdrawal.

The four NOUE EALs were revised on December 29, 1999, in Revision 33 to EPIP 1.2, which was also part of Revision 14 to the Emergency Plan’s Index.

The licensee entered the inspectors’ preliminary finding (current EAL scheme not in accordance with one of the standard EAL schemes endorsed by Regulatory Guide 1.101) in its corrective action process as significant condition report CAP034784, which required a formal root cause analysis and identification of corrective actions.

Analysis: Point Beach’s EP program failed to maintain the Emergency Plan’s scheme of EALs such that all initiating conditions, which had been assumed in the licensee’s approved EAL basis (NUREG-0654, Revision 1, as amended in NRC’s 1984 SER), would result in emergency classifications at appropriate levels. Specifically, two GE, two Alert, and four NOUE EALs were changed, resulting in decreases in effectiveness of the Emergency Plan without a commensurate decrease in the approved basis of the Emergency Plan. As a result, the licensee might not have classified several emergency events at the same level that would have resulted from use of the 1984 NRC-approved EAL scheme. A decrease in the GE level of classification would result in decreased protective action recommendations for the offsite authorities, and potentially a reduction in the level of protective action decisions forwarded to the public by offsite authorities. A decrease in the Alert and NOUE levels of classification could also have resulted in a reduced level of response by offsite authorities if their level of response was based to some extent on which of the four emergency classes was associated with the licensee’s emergency declaration.

Enforcement: 10 CFR 50.54(q) provides, in part, that a licensee shall follow and maintain in effect emergency plans which meet the standards in §50.47(b). The licensee may make changes to the emergency plans without NRC approval only if the changes do not decrease the effectiveness of the plans and the plans, as changed, continue to meet the standards of §50.47(b). Proposed changes that decrease the effectiveness of the approved emergency plans may not be implemented without application to and approval by the NRC.

10 CFR 50.47(b) requires that the onsite emergency response plans for nuclear power reactors meet each of 16 planning standards, of which, planning standard 4 states, in part, that a standard emergency classification and action level scheme is in use.

Chapter 4 of the Emergency Plan (Revision 38, dated February 6, 2002) stated that the licensee's emergency classification system was based on NUREG-0654, Revision 1, Appendix 1.

Contrary to the above, from October 1998 through December 1999, the licensee made changes without NRC approval to the EALs in Appendix B of its Emergency Plan that decreased the effectiveness of the Plan and resulted in use of a non-standard scheme of EALs. For example, as discussed above, the licensee made significant changes to both the content and format of its EAL scheme, with resultant decreases in effectiveness of 8 EALs. The licensee wrote CAP034784 for this finding. Also, ACE001405, associated with CAP034833, "Inconsistency In Evaluation/Interpretation of EAL," was initiated. The failure to receive NRC approval prior to changing the EAL scheme is an Apparent Violation of 10 CFR 50.54(q), associated with emergency planning standard 10 CFR 50.47(b)(4) (AV 50-266/03-07-05; 50-301/03-07-05). The details of this apparent violation were communicated to the licensee in a letter dated December 2, 2003, and a predecisional enforcement conference to discuss it further was conducted on January 13, 2004.

b.3 Failure To Maintain Ability To Implement An NOUE EAL

Introduction: A Green, Non-Cited Violation associated with emergency planning standard 10 CFR 50.47(b)(4) was identified. Specifically, the licensee failed to ensure that the facility seismic monitors were capable of supporting implementation of an NOUE EAL.

Description: EAL 6.1.1.1 required declaration of an NOUE if ground shaking was felt or if an indicator light (set to actuate at greater than or equal to .01g) was observed on two or more of the four seismic monitors. The seismic event indicating lights actuate when sensed ground motion exceeded the setpoint, then extinguish when ground motion was reduced to below the setpoint. The as-found setpoint for all three seismic monitors (one monitor, SEI-6211, had been sent to Sweden for repair) exceeded .03g. The licensee discovered the incorrect setpoints in response to the inspectors' questions regarding the seismic EALs. The licensee determined that the setpoint control document, STPT 22.1, dictated a correct setpoint of .01g. However, the only test conducted to verify functionality of the seismic monitors, the imbalance test, did not verify the setpoint and would not have indicated a failed test for a setpoint above .01g. Additionally, there was no system or procedure to periodically verify the accuracy of the as-found setpoints. The inspectors determined that the failure to maintain the setpoints created a condition such that NOUE EAL 6.1.1.1 could not be implemented using the seismic monitor indications.

Analysis: The failure to ensure that EP equipment was maintained ready to support implementation of the Emergency Plan was a performance deficiency that was more than minor because it was associated with a cornerstone attribute and affected the EP cornerstone objective (to ensure the adequate protection of the public health and safety.) The finding involved the failure to ensure that seismic monitoring equipment, necessary for implementation of NOUE EAL 6.1.1.1, remained functional with reasonable assurance. When processed through the EP SDP, the finding was found to have very low safety significance because a NOUE could be declared based on ground shaking. Consequently, the lack of accurately set seismic monitors only degraded the capability to implement EAL 6.1.1.1, and was therefore not a planning standard function failure. The inspectors identified this finding during review of CAPs that were written during the inspection as a result of the inspectors' concerns with the seismic monitors. The licensee wrote CAP034787 for the setpoint control concerns.

Enforcement: 10 CFR 50.54(q) provides, in part, that a licensee shall follow and maintain in effect emergency plans which meet the standards in §50.47(b). 10 CFR 50.47(b) requires that the onsite emergency response plans for nuclear power reactors meet each of 16 planning standards, of which, planning standard 4 states, in part, that a standard emergency classification and action level scheme, the bases of which include facility system and effluent parameters, is in use. The Point Beach Emergency Plan, Appendix B, contains EALs, including EAL 6.1.1.1, which must be implemented based on in-plant parameters. Contrary to this, the licensee failed to maintain the seismic monitors in a functional condition such that EAL 6.1.1.1 could be implemented. Because the finding was determined to be of very low safety significance and was entered into the licensee's corrective action program as CAP034787, this violation is being treated as a Non-Cited Violation, consistent with Section VI.A of the NRC Enforcement Policy (NCV 50-266/03-07-06; 50-301/03-07-06).

The inspectors reviewed a sample of 17 EALs to determine if the indications would be available in the control room in a reasonable time for operators to implement the EALs. During this review, the inspectors identified that indications for two seismic activity EALs, 6.1.1.2 and 6.1.1.3, would not be available in a timely manner during a seismic event due to inadequate shift staffing. The inspectors determined this was a violation of NRC regulations, which is described in Section 3.2.b.2 of this report.

3.7 Conclusions of the Emergency Preparedness Phase of the IP 95003 Inspection

In summary, although the EP program at Point Beach has several challenges to address in both the immediate and near-term, the inspectors concluded that Point Beach can implement its EP program adequately to protect the public health and safety and the environment. This conclusion is largely based on the observation of the August 14, 2003, drill, where the licensee demonstrated that they could implement the Emergency Plan in a manner commensurate with protecting public health and safety. The positive results of this exercise were consistent with observations of prior drills in November 2002 and June 2003. The Apparent Violation associated with the failure to maintain a standard scheme of Emergency Action Levels, the Unresolved Item and drill critique observations associated with protective action recommendations, and the NCV associated with accurate reporting and tracking of the control room communicator in the emergency preparedness performance indicators, were all indications of potentially significant misunderstandings of EP regulations and guidelines. The NCVs associated with seismic monitors, ability to implement the EALs, and lack of a formal EP staff training program were examples of inadequate licensee processes for maintaining the EP program. The inspectors concluded that implementation of the corrective action program for the EP area was adequate, but that the evaluation of extent of condition of problems continued to show some challenges. The inspectors noted that many of these problems originated under previous EP department management, and that the current staff and managers, while relatively inexperienced, were dedicated to the identification and correction of those problems.

4. Engineering, Operations, and Maintenance

As discussed in Inspection Reports 50-266/01-17(DRS); 50-301/01-17(DRS), dated April 3, 2002, and 50-266/02-15(DRP); 50-301/02-15(DRP), dated April 2, 2003, and Final Significance Determination Letters dated July 12, 2002, and December 11, 2003, the Red inspection finding for the AFW/IA issue and the Red inspection finding for the AFW orifice plugging issue were caused by design process weaknesses and faulty knowledge of the design basis of a risk-significant system, AFW. Consequently, the focus of the third and final phase of the IP 95003 was design engineering. To assess this area, the inspectors conducted a vertical slice of two risk significant systems: component cooling water (CCW) and 125-volt direct current (VDC). The inspectors also reviewed AFW corrective actions and, in response to the electrical grid disturbance in the eastern United States on August 14, 2003, the design basis, licensing basis, and as-built configuration of several AC electrical distribution systems.

And lastly, the inspectors reviewed selected aspects of the operations and maintenance areas, with an emphasis on the interface of engineering with these areas.

To meet the five overall objectives of the 95003 inspection, as listed in Section 1 of this report, the inspectors used the guidance of IP 95003 and reviewed the following key attributes during this phase of the inspection:

a. Design

b. Human Performance

c. Procedure Quality

d. Equipment Performance

e. Configuration Control

As with the review of the corrective action program aspects of problems in the EP area during the EP phase of the inspection, the inspectors reviewed the corrective action program aspects of problems in engineering during this phase of the 95003 inspection.

4.1 Engineering

4.1.1 125-VDC System

4.1.1.1 Design Basis, Licensing Basis, and As-Built Review

a. Inspection Scope

The inspectors reviewed the design basis, licensing basis, as-built design features, and several recent modifications of the 125-VDC system to determine if the system was able to perform the intended safety functions with a sufficient margin. Included in this review was a detailed walkdown to determine if the system was in a configuration to support its safety function. The inspectors reviewed a sample of corrective actions involving design control issues, the control of design and licensing input and output information, the adequacy of design modifications, and selected 10 CFR 50.59 evaluations related to design and procedure changes, and compared the as-built design with the current design and licensing basis.

b. Observations and Findings

For the review of the 125-VDC system using the five key attributes of IP 95003, no findings of greater than very low safety significance (Green) were identified and the system was found to be operable. As discussed in Section 4.1.4, minor corrective action program problems were identified. Of greater concern, discussed below, were a non-conservative TS surveillance requirement for the safety-related battery chargers, a high work load in engineering that has resulted in engineering staff frequently being reactive to plant issues (instead of pro-active), and a failure to maintain system calculations up-to-date.

Although the licensee had identified the need to update the calculations, the licensee had not fully evaluated the extent of the problem nor aggressively pursued its resolution. As of the end of the inspection, the licensee appropriately reassessed the priority assigned to updating the calculations.

b.1 125-VDC TS Surveillance Requirement

Introduction: The inspectors identified that the TS surveillance requirement (SR) for testing the battery chargers was non-conservative in relation to the design basis calculation for battery charger sizing. This failure to assure that the regulatory requirements and the design basis of the plant were accurately maintained was determined to be of very low safety significance and was dispositioned as a Green, Non-Cited Violation. Additionally, the TS bases for the SR did not agree with the FSAR.

Description: Calculation 2003-0046, “Battery Chargers Sizing and Current Limit Setpoint,” Revision 0, established a minimum battery charger size (minimum current limit setpoint) for the D-07, D-08, D-09, D-107, D-108, and D-109 battery chargers of 293 amps (amperes) DC. This value was calculated using the FSAR Section 8.7.2 description of the battery charger as an acceptance criterion. The FSAR stated, “The battery chargers have been sized to recharge any of their respective partially discharged batteries within 24 hours while carrying normal load.” The licensee then established the minimum current value by conservatively establishing current output for both the normal

DC load and the discharged battery.

Technical Specification SR 3.8.4.6, however, tested the batteries by verifying that battery chargers D-07, D-08, and D-09 each supply ≥ 203 amps at ≥ 125 V for ≥ 8 hours, and battery chargers D-107, D-108, and D-109 each supply ≥ 273 amps at ≥ 125 V for ≥ 8 hours. The TS bases stated, "These requirements are based on the design capacity of the chargers. According to Regulatory Guide 1.32 ["Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants"], the battery charger supply is required to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensures that these requirements can be satisfied." These requirements did not reflect both the FSAR description and the battery charger sizing calculation which appeared to support a requirement of 293 amps at ≥ 24 hours.

Based upon the inspectors' finding, the licensee wrote CAP050366 and reviewed the surveillance procedures for the battery chargers. In this CAP, the licensee attempted to demonstrate that the existing surveillance test adequately ensured that the battery chargers could recharge the batteries in 8 hours while supporting DC loads. By taking advantage of existing conservatisms in the battery charger sizing calculation and comparing these new required outputs for the chargers to the surveillance test procedure, the licensee was able to conclude that the battery chargers were operable.

Although the licensee had been able to demonstrate by calculation the operability of the battery chargers, the licensee had failed to maintain an accurate design basis and license basis for the chargers.

The inspectors also determined that TS SR 3.8.4.6 appeared to be non-conservative in relation to the design basis calculation for battery charger sizing.

Analysis: This failure to assure that the regulatory requirements and the design basis of the plant were accurately maintained is a violation of the requirements in 10 CFR Part 50, Appendix B, Criterion III, "Design Control." This finding was determined to be more than minor because it affected the mitigating systems cornerstone objective. The finding screened as Green in the SPD Phase 1, Mitigation Systems, question 1. Because this issue was a design deficiency that was confirmed not to result in the loss of function in accordance with GL 91-18, "Information to Licensees Regarding NRC Inspection Manual Section on Resolution of Degraded and Nonconforming Conditions," Revision 1.

Enforcement: 10 CFR Part 50, Appendix B, Criterion III, "Design Control," states, in part, that measures shall be established to assure that applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures, and instructions.

Contrary to this, the licensee failed to assure that the design basis of the safety-related battery chargers was accurately translated into TS SR 3.8.4.6. This violation was determined to be of very low safety significance because the licensee was able to subsequently demonstrate, through calculation, that the battery chargers were operable. Since this design control violation was captured in the licensee's corrective action program (CAP050366), it is considered a Non-Cited Violation (NCV 50-266/03-07-07; 50-301/03-07-07), consistent with Section VI.A.1 of the NRC Enforcement Policy.

b.2 125-VDC System Calculations

Introduction: The voltage drop, baseline cable ampacity, and short-circuit calculations needed revision and no longer reflected the configuration of the 125-VDC system at Point Beach Nuclear Plant (PBNP). The battery sizing and 125-VDC loading calculation had been revised but was still in draft form and the calculation of record no longer reflected the present plant configuration. The inspectors identified that the licensee had performed modifications to electrical equipment in the 125-VDC system without updating affected design basis calculations. This left the plant in a configuration that was not supported by an updated design basis. This failure to maintain the design basis of the plant was determined to be of very low safety significance and was dispositioned as a Green, Non-Cited Violation.

Description: Design change package MR 97-014 documented a plant modification that was designed to improve selective coordination; to provide better independence between Unit 1, Unit 2, and common loads; to remove some nonsafety-related loads from the safety-related buses; and to reduce the loading on certain safety-related buses. The modification changed loads fed from both the D-01 and D-02 125-VDC buses.

To support this modification, the licensee issued calculation addendum E-09334-472-DC.3 to address voltage drop. This calculation provided a justification that the terminal voltage for the relocated loads was acceptable; however, it did not evaluate voltage for loads that were not relocated. Also, the calculation provided a qualitative analysis of voltage drop, but it did not provide a true design basis calculation for voltage drop in the 125-VDC system. This was recognized within the calculation by a statement in the background section that "A formal revision of WE [Wisconsin Electric] calculations N-93-056 and N-93-057, Battery D05 (D06) DC System Sizing, Voltage Drop, and Short Circuit Calculations, is required."

The inspectors determined that for a major realignment of loads, such as that performed by MR 97-014, the design basis voltage drop calculation should have been revised to reflect the new loading configuration. While calculation addendum E-09334-472-DC.3 addressed voltage drop considerations qualitatively, it was used more as a justification for operability rather than as a true design basis calculation. Additionally, the licensee implemented the modification in seven separate phases over several years. Each phase was implemented similarly to a completed modification. Calculation addendum E-09334-472-DC.3 addressed the MR 97-014 as a complete design change but there were no calculations to support the interim changes made by each phase of the modification. The inspectors determined that this was another instance of the licensee operating in a design configuration that was not supported by a design basis voltage drop calculation. The inspectors reviewed calculation addendum E-09334-472-DC.3 and determined that the calculation was adequate. As a result, although the licensee had qualitatively determined that the loads in the 125-VDC system were operable, the design basis of the plant was not being maintained even though major configuration changes had been made.

The inspectors also reviewed design change package MR 03-005, implemented in May 2003. This modification repowered the turbine-driven AFW pump recirculation valves 1AF-4002 and 2AF-4002. For this design change, the licensee performed a more thorough analysis; however, the calculation was embedded within the modification and was not a stand-alone calculation as required by the current plant procedure, NP 7.2.1, "Plant Modifications." The inspectors noted that this was another example of the licensee's failure to update the design basis calculations. However, since the analysis contained within MR 03-005 determined that the change was technically acceptable and that no operability concerns existed, there was no loss of function associated with this issue.

Although the licensee was able to determine the operability and functionality of DC loads for both MR 97-014 and MR 03-005, the existing design basis calculations had not been adequate. This was further compounded by the failure of the licensee to update the design basis calculations since MR 97-014 was implemented.

Analysis: This failure to assure that the design basis of the plant was accurately maintained in regard to the 125-VDC voltage drop calculations is a violation of the requirements in 10 CFR Part 50, Appendix B, Criterion III, "Design Control." This finding was determined to be more than minor because it affected the mitigating systems cornerstone objective.

The finding screened as Green in the SPD Phase 1, Mitigation Systems, question 1. This issue was a design deficiency that was confirmed not to result in the loss of function in accordance with GL 91-18.

Enforcement: 10 CFR Part 50, Appendix B, Criterion III, "Design Control," states, in part, that measures shall be established to assure that applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures, and instructions.

Contrary to this, the licensee failed to assure that the design basis of the 125-VDC system was correctly translated into specifications when major configuration changes were made to the system and the system voltage drop calculations were not revised to reflect these changes. This violation was determined to be of very low safety significance (Green), because the licensee was able to demonstrate, through analysis, that the effects of the modifications did not affect functionality of equipment powered by the 125-VDC system. And because this design control violation was captured in the licensee's corrective action program (CAP002410, CAP034396, CAP050403), it is considered a Non-Cited Violation (NCV 50-266/03-07-08; 50-301/03-07-08) consistent with Section VI.A.1 of the NRC Enforcement Policy.

The licensee's overall efforts to improve calculations were included in Excellence Plan action plan OP-14-005, "Validate and Integrate Calculations and Setpoints." As with inspectors' observations about the timeliness of action plan actions for setpoints (discussed in Sections 4.1.4 and 4.1.5), the due dates of action plan actions for reviewing and revising calculations were not timely. The licensee subsequently revised the due dates. The revised dates were appropriate.

4.1.2 Design Basis and As-Built Review of AC Systems, Including the Offsite Electrical Distribution Grid and Plant Electrical System Interface

a. Inspection Scope

As part of the review of the 125-VDC system and in response to the electrical grid disturbance in the eastern United States on August 14, 2003, the inspectors reviewed the design basis, licensing basis, and as-built configuration of several AC systems at Point Beach. In addition, some recent CAPs related to the AC systems were reviewed.

b. Observations and Findings

As with the review of the 125-VDC system using the five key attributes of IP 95003, no findings of greater than very low safety significance were identified during the review of the AC systems and the systems were found to be operable. As discussed below, minor problems were identified with calculations, procedures, and corrective actions. Of more concern was the inspectors' observations that engineering staff had a weak understanding of system design basis. In addition, the inspectors determined that issues involving high-energy line break/equipment qualification were not resolved in a timely manner.

b.1 Offsite Electrical Distribution Grid Issues

The inspectors reviewed licensee documentation and held discussions with operations and engineering staff to assess the adequacy of plant systems and procedures to ensure the availability of offsite power. As a result, the inspectors made the following observations.

- The TS basis for Limiting Condition for Operation (LCO) 3.8.1, "AC Sources," stated that the plant could withstand a Design Basis Accident with only one offsite source without losing offsite power. The inspectors questioned this statement and the licensee subsequently determined that it was incorrect and would have to be changed. The problem with the basis required no change to the LCO.

- Fast Transfer of 13.8-Kilovolt (kV) Station Buses. The inspectors identified that the licensee did not have a documented analysis that verified that the safety-related electrical buses would remain connected to the offsite source following the failure of one of the two station high voltage auxiliary transformers. Also, there were no procedures in-place to alert operators of the increased risk of grid separation for certain allowable onsite electrical system alignments. This risk would be increased if one or both of the unit auxiliary transformers (UATs) were already out-of-service prior to the transfer, because loading on the operating high voltage transformer after the transfer would be considerably more than when the UAT(s) was/were in-service.

The failure to analyze the electrical distribution system for limiting alignments that could lead to the complete loss of offsite power to the safety-related buses is a violation 10 CFR Part 50, Appendix B, Criterion III, “Design Control.” However, this issue did not have a significant impact on safety because the failure of a high voltage transformer concurrent with an accident was highly unlikely. In addition, failure of a high voltage transformer with two UATs out-of-service was considered very unlikely. Consequently, the issue is considered minor, and thus, it is not subject to enforcement action in accordance with Section IV of the NRC’s Enforcement Policy. The licensee wrote CAP050414 to address this issue.

- Procedure for Assuring Acceptability of Grid Voltages. During the initial part of the inspection, plant engineers were unaware of operations procedures and controls for assuring the acceptability of grid voltages. About 2 weeks later during the inspection and in response to inspectors’ questions, licensing engineering staff were informed by operators that Procedure OP-2A, “Normal Power Operation,” addressed this issue and that, in addition, measures had been implemented by the grid operator, American Transmission Company (ATC), in 1997 to preclude spurious separation of the Point Beach buses from offsite power. These measures consisted of software with a “real time” contingency alarm that would alert ATC personnel if grid conditions were such that a single contingency, such as the trip of a Point Beach unit or a transmission line failure, would cause Point Beach switchyard voltage to decrease too low. ATC personnel would then notify the Point Beach control room. The measures by ATC appeared to be appropriate, but were not in OP-2A, so the Point Beach operator response to such a notification was uncertain. In response, the licensee wrote CAP050227 and initiated actions to revise Procedure OP-2A.

  After engineering personnel became aware of ATC’s measures, they were not able to retrieve an analytical basis for the contingency alarm setpoint. Calculation N-93-098 determined the reset setpoint for the degraded voltage relays, but it did not determine tolerances associated with this parameter so that the maximum value was not determined.

  A maximum value was needed to compare with available bus voltage to verify that the degraded voltage relays would reset under worst case grid and plant loading conditions. In addition to the lack of a maximum reset value, there was no calculation that determined the safety-related 4160-V bus voltage that would result from the minimum grid voltage of 348.5 kV used as the alarm setpoint by ATC. The inspectors attempted to estimate the relationship between 4160-V bus voltage and switchyard voltage using Calculation N-93-002, but due to significant errors in the calculation, this was not successful. The inspectors were subsequently able to determine from engineering evaluations performed by the licensee during this inspection that the ATC setpoint was conservative relative to maintaining the availability of the offsite source.

The failure to implement adequate procedures to enable operators to determine the operability of the offsite power source is a violation 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings.” However, this issue was of minor safety significance because available data indicated that grid availability at Point Beach was very high. The licensee had not received any notifications of actual alarms from ATC for potentially unacceptable voltages since the implementation of the real time network analyzer in 1997. Because this issue was minor, and adequate measures were now in-place to ensure the availability of the offsite source to mitigate an accident, it is not subject to enforcement action in accordance with Section IV of the NRC’s Enforcement Policy. The licensee wrote CAP050227 to address this issue.

These three issues with the offsite power supplies (the inaccurate TS basis statement, lack of analysis of limiting grid alignments, and weak procedure guidance for assuring acceptability of grid voltage) were not operability concerns but did demonstrate weaknesses in engineering communication with operators, lack of clear understanding of the design basis for degraded voltage protection, and lack of rigor in the degraded grid calculation.

b.2 Environmental Qualification of Electrical Equipment

1. The inspectors identified a Green, Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action,” for the licensee’s failure to implement timely corrective actions for safety-related electrical equipment in the primary auxiliary building (PAB) that was not environmentally qualified.

   Description: On January 18, 1998, the licensee identified (CAP001559) that the station’s newly revised HELB analysis had identified areas in the PAB that had previously been considered as mild environments but were now considered as harsh environments. The licensee documented this issue in CAP001559. The postulated HELB that could cause these harsh environments in the PAB was the potential rupture of the 3-inch line in the PAB supplying steam to the radioactive waste system and to the turbine-driven AFW pumps. The licensee determined that because of these harsh environments there was electrical equipment important to safety that was not evaluated in the environmental qualification (EQ) program, a condition adverse to quality. At the time, the licensee performed an operability determination (OD) and concluded that electrical equipment needed to shut down the plant if the 3-inch steam line break were to occur was operable but degraded.

   As a corrective action, the licensee installed HELB wall barriers and a blow-off panel in the CCW heat exchanger room to protect the non-EQ electrical equipment.

   In June 2003, the inspectors reviewed CAP001559 and the associated OD. The OD had been revised 12 times since 1998, but the corrective action for this condition adverse to quality had still not been completed. Additionally, the inspectors determined that the current OD had not adequately evaluated environmental effects on all electrical equipment that potentially could be subject to a harsh environment. The inspectors concluded that the licensee had failed to correct this condition adverse to quality for over 5 years and had failed to adequately address operability concerns associated with the environmental qualification of affected electrical equipment. After communicating this finding to the licensee, the OD was again revised. The inspectors reviewed the new evaluation and again determined that the OD did not adequately address the environmental qualification of affected electrical equipment.

In August 2003, the licensee completed the corrective action by erecting HELB wall barriers and installing a blow-off panel in the CCW heat exchanger room. This corrective action eliminated the EQ concerns associated with the potential rupture of the 3-inch steam line in the PAB.

<u>Analysis</u>: The failure to correct this condition adverse to quality was more than minor because if left uncorrected, it would become a more significant safety concern. Failure to correct problems with environmental qualification of electrical equipment could potentially have adverse effects on the capability to prevent or mitigate the consequences of accidents. However, the inspectors determined that this finding was of very low significance and screened this finding as Green in the SPD Phase 1, Mitigation Systems, question 1. The corrective action issue was associated with a qualification deficiency that did not result in a loss of function per GL 91-18. Additionally, in August 2003, the licensee completed the corrective action for this condition by erecting HELB wall barriers and installing a blow-off panel in the CCW heat exchanger room. This eliminated the EQ concerns associated with the potential rupture of the 3-inch steam line in the PAB.

<u>Enforcement</u>: 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action,” requires, in part, that conditions adverse to quality, be identified and corrected. Contrary to this, as of June 2003, the licensee had not corrected a condition adverse to quality associated with safety-related electrical equipment in the PAB that was not environmentally qualified. Specifically, for over 5 years, the licensee relied on an OD that did not adequately evaluate environmental effects on all electrical equipment instead of correcting the existing condition.

Because the finding was in the licensee’s corrective action program (CAP001559), this violation is being treated as a Non-Cited Violation (NCV 50-266/03-07-09; 50-301/03-07-09) consistent with Section VI.A.1 of the NRC Enforcement Policy.

2. The inspectors also identified a Green, Non-Cited Violation of 10 CFR 50.49(f) for the failure to environmentally qualify the equipment.

<u>Description</u>: As discussed previously, when the inspectors reviewed the OD associated with CAP001559 in June 2003, it had been revised 12 times. Revision 12 identified all equipment evaluated for harsh conditions in the PAB:

- AFW MOVs,

- Equipment That Could Adversely Affect Reactor Coolant Pump Seal Cooling,
- Safety-Related MCCs,
- Electrical Cables,
- Charging Pump Motors, and
- CCW Pump Motors.

The inspectors reviewed the evaluation for this equipment and did not identify any major discrepancies. However, the licensee could not provide a list of all required equipment for safe shutdown of the plant in the case of the 3-inch steam line rupture. Additionally, the inspectors determined that several items were not evaluated by the OD. Specifically, the licensee had not evaluated the following for a harsh environment:

- electrical terminal connection boxes,
- electrical pull boxes,
- electrical junction boxes, and
- nonsafety-related MCCs that could prevent satisfactory accomplishment of safety functions.

In response to the inspectors' concern regarding Revision 12 of the OD, the licensee revised the OD. The inspectors reviewed this updated OD and determined again that the evaluation did not address their concerns. Specifically, while the licensee attempted to address the potential effects of a harsh environment on electrical enclosures (terminal boxes, etc.), the licensee relied on EQ evaluations performed by other nuclear power plants for their plant specific configurations. The inspectors determined that the licensee's evaluation did not bound the configurations at Point Beach.

As discussed earlier in this report, the licensee completed the corrective action for this condition in August 2003 by erecting HELB wall barriers and installing a blow-off panel in the CCW heat exchanger room. This corrective action eliminated the EQ concerns associated with the potential rupture of the 3-inch steam line in the PAB. However, the licensee had failed to adequately environmentally qualify electrical equipment important to safety in accordance with the requirements in 10 CFR 50.49(f).

<u>Analysis</u>: The failure to correct this condition adverse to quality is more than minor because it affected the mitigating systems cornerstone. Failure to environmentally qualify electrical equipment could potentially have adverse effects on the capability to prevent or mitigate the consequences of accidents. However, this finding screened as Green in the SPD Phase 1, Mitigation Systems, question 1. This issue was a design deficiency that did not result in the loss of function per GL 91-18.

<u>Enforcement</u>: 10 CFR 50.49(f) states, in part, that electrical equipment important to safety must be qualified by one of the following methods:

- testing an identical item of equipment under identical conditions with a supporting analysis to show that the equipment to be qualified is acceptable,

- testing a similar item of equipment with a supporting analysis to show that the equipment to be qualified is acceptable,

- experience with identical or similar equipment under similar conditions with a supporting analysis to show that the equipment to be qualified is acceptable, and

- analysis in combination with partial type test data that supports the analytical assumptions and conclusions.

Contrary to this, the licensee had identified that equipment important to safety located in the PAB would be susceptible to a harsh environment during a postulated HELB, but failed to environmentally qualify this electrical equipment. Therefore, because this violation of 10 CFR 50.49(f) was captured in the licensee's corrective action program (CAP001559), it is considered a Non-Cited Violation (NCV 50-266/03-07-10; 50-301/03-07-10) consistent with Section VI.A.1 of the NRC Enforcement Policy. The licensee's overall efforts for the high energy line break issue was contained in Excellence Plan action plan EQ-15-006, "High Energy Line Break Project."

b.3 Miscellaneous AC Electrical Distribution System Issues

During the inspectors' review of licensee documentation related to the design and as-built configuration of the electrical distribution system, the following additional observations regarding licensee design control practices were made.

- MOV Voltage Calculation Used Non-Conservative Methodology. Calculations used non-conservative methodology for determining voltage at motor control centers (MCCs) serving motor-operated valves (MOVs). Calculation N-94-009 determined the minimum voltage at MCCs based on the results of Calculation N-93-002, which determined steady state voltages on the safety-related buses. Calculation N-93-002 treated MOVs as intermittent loads and considered them to be off for steady-state conditions. This resulted in a non-conservative result for use in MOV voltage calculations because there would be an additional voltage drop in the circuit elements upstream of the MCCs when the MOVs were operating. In response to the inspectors' question, the licensee issued CAP050174, which evaluated additional margins showing that MOV voltage was acceptable. Because MOV operability was not compromised, this design control violation constitutes a violation of minor significance, not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. However, it is another example of a design control weakness.

- The inspectors identified that the transfer setpoint for the vital inverter static transfer switches was not periodically calibrated to assure premature transfer would not occur and that some setpoints were not contained in the station's setpoint document. The vital inverters may be powered from a nonsafety-related 480-V source if the safety-related 125-VDC source became unreliable. The automatic transfer to the nonsafety-related source was accomplished through a static transfer switch that monitored inverter output. The transfer to the nonsafety-related source was a nonsafety-related function, but preventing spurious transfer was a safety-related function and depended on voltage and time delay setpoints. In response to the inspectors' inquiries, the licensee identified that these setpoints were not periodically calibrated. In addition, the slow transfer time delay setpoints for the red channel and blue channel inverters were not listed in the setpoint document. Because maintenance records indicated that there had been no spurious transfers due to setpoint errors, this design control and procedure violation constitutes a violation of minor significance, not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. It indicated weaknesses in the licensee's maintenance and configuration control programs. The licensee wrote CAP050164 to document this issue and track associated corrective actions.

Though the safety consequences of the above examples were minor, the examples indicate a lack of attention to detail by the engineering staff in assessing issues related to plant configuration and design control in the electrical area.

4.1.3 Component Cooling Water (CCW) System

4.1.3.1 Design Basis, Licensing Basis, and As-Built Review

a. Inspection Scope

The inspectors reviewed the design basis, licensing basis, as-built design features, and several recent modifications of the CCW system to determine if the system was able to perform the intended safety functions with a sufficient margin. Included in this review was a detailed walkdown to determine if the system was in a configuration to support its safety function. The inspectors reviewed a sample of corrective actions involving design control issues, the control of design and licensing input and output information, the adequacy of design modifications, and selected 10 CFR 50.59 evaluations related to design and procedure changes, and compared the as-built design with the current design and licensing basis.

The inspectors reviewed CCW system calculations; related CAPs; system drawings; and design basis documents, including the FSAR, TSs, the licensing basis summary, and the CCW DBD, to determine if the CCW system was able to perform its intended safety function. The inspectors reviewed CCW heat exchanger thermal performance, design temperature, and CCW surge tank minimum volume calculations to determine the adequacy of assumptions and methodology used. These were also reviewed to determine if calculations were consistent with design basis documents.

The inspectors also reviewed the CCW system training lesson plan for consistency with current design basis and parameters. The lesson plan included major system components, objectives, and operating parameters.

The inspectors also reviewed some recent CCW-related CAPs to assess whether design and licensing operating parameters were being controlled. Corrective actions were reviewed to assess the effectiveness of maintaining CCW system design. The inspectors reviewed some recent CAPs related to design basis temperature and flow limits and requirements, heat exchanger tube plugging limits, and calculation deficiencies.

b. Observations and Findings

For the review of the CCW system using the five attributes of IP 95003, no findings of greater than very low safety significance (Green) were identified and the system was found to be operable. As discussed below, the inspectors identified a minor violation for inadequate control and evaluation of relief valve setpoint changes; a Green, NCV for the failure to include certain manual CCW valves in the inservice testing program; and a minor procedure violation regarding an Appendix R replacement CCW pump motor

b.1 CCW Relief Valve Setpoint Changes

The inspectors reviewed calculation N-93-71, "1(2)CC-754A, 754B, 1(2)CC-759A, 759B (Group 11) MOV Differential Pressure Calculation," Revision 0, dated February 1, 1994. A portion of this calculation determined the most limiting pressure in the CCW system occurred upstream of reactor coolant pump CCW outlet valves 1(2)CC-759A and 1(2)CC-759B. The calculation stated that this system pressure would be limited to 145 pounds per square inch - gauge (psig) based on the setpoint of CCW relief valves 1(2)CC-763A and 1(2)CC-763B. This value was used to determine the maximum differential pressure across the MOVs when they were required to be closed. Valves 1(2)CC-759A and 1(2)CC-759B were manual containment isolation valves, as shown on FSAR Figures 5.2-17 and 5.2-18, dated June 2002.

The inspectors questioned the basis of the 145 psig upstream pressure value. It was the inspectors' understanding that the setpoints of CCW relief valves 1(2)CC-763A and 1(2)CC-763B had been increased to 150 psig. In addition, the setpoint value used in the calculation did not appear to account for relief valve accumulation.

In response to these questions, the licensee stated that the setpoints for relief valves 1(2)CC-763A and 1(2)CC-763B had been changed from 145 psig to 150 psig as a result of CAP002914. However, the inspectors noted that this setpoint change had failed to consider the impact of the change on the inputs to calculation N-93-71 and on the isolation function of valves 1(2)CC-759A and 1(2)CC-759B. In addition, calculation N-93-71 did not include any additional allowances for relief valve setpoint uncertainty or accumulation. The licensee wrote CAP050229 on September 17, 2003, to address these issues. The licensee also verified that valves 1(2)CC-759A and 1(2)CC-759B had sufficient margin to close and remained operable.

After additional investigation, the licensee identified that the 10 CFR 50.59 evaluation associated with the relief valve setpoint change (SCR 2002-0184, dated April 26, 2002) did not adequately address the impact of the relief valves' 25 percent accumulation value on the system piping. CAP050367 was written on September 23, 2003, to address this issue. This CAP identified actions to revise the 50.59 evaluation, establish the extent of condition, and review the control of the setpoint change process. The inspectors also noted that the PBNP self-assessment earlier in 2003 had not identified this concern.

Although the failure to adequately control and evaluate the relief valve setpoint change had been identified during the inspection, the licensee verified that valves 1(2)CC-759A and 1(2)CC-759B had sufficient margin to close and remain operable. The inspectors determined that this issue was not a precursor to a significant event, this issue would not become a more significant safety concern if left uncorrected, this issue was not related to performance indicators, and it did not directly affect any of the cornerstone attributes. Therefore, the failure to adequately control and evaluate the relief valve setpoint change was a violation of minor significance that was not subject to enforcement action in accordance with Section IV of NRC's Enforcement Policy. The licensee documented this failure in CAP050229 and CAP050367. Licensee overall efforts to improve relief valve performance were part of Excellence Plan action plan EQ-16-010, "Make Improvements in the Relief Valve Program."

During the review of this area, the inspectors also identified a problem with the setpoints in several EOPs. This issue is discussed in Section 4.1.5.

b.2 Appendix R Replacement CCW Pump Motor

Routine Maintenance Procedure RMP 9006-4, "Component Cooling Water Pump Motor Emergency Replacement," Revision 2, Section 2.4, listed two motors as available spares (Lot Numbers 9101179 and 9100242). The inspectors asked the licensee to verify the availability and acceptability of these two motors. The licensee verified that the motor located in Warehouse 3 (Lot Number 9100242) was correct. However, the licensee found that the lot number of the other spare CCW motor had been changed from 9101179 to 9033181, and that the motor was located in the West Quonset Hut at the time of the inspection. The licensee also stated that this spare motor (Lot Number 9033181) had a higher locked rotor current rating (kVA (kilovolt-ampere) Code G) than the installed CCW pump motors (kVA Code D), notwithstanding a licensee evaluation performed per CA018346 that determined the motor was acceptable for use as an Appendix R spare. The licensee wrote CAP050276 on September 18, 2003, to correct the lot number listed in RMP 9006-4.

The inspectors then questioned the acceptability of using the spare motor with the higher locked rotor current rating (kVA Code G) without resetting the affected motor supply breaker. The licensee performed an additional evaluation and concluded that this motor should not be used as a spare CCW motor. The licensee then wrote CAP050398 to supersede CAP050276 and remove the reference to the second spare motor from Procedure RMP 9006-4.

The inspectors noted that the use of this spare motor had been previously questioned during the 1999 CCW system self-assessment (S-A-ENG-99-007). It appeared that Spare Parts Equivalency Evaluation Document (SPEED) 99-003 had been initiated to approve the use of this motor as an Appendix R spare, but the SPEED had not been approved at the time of the 1999 self-assessment. The resolution of this self-assessment issue was documented in Engineering Work Request S-A-ENG-99-007, Action Number 6, on December 22, 1999, which concluded that this motor could not be used without modifications to the electrical switchgear, and SPEED 99-003 would be canceled.

The inspectors did not determine why Procedure RMP 9006-4 included a reference to an inappropriate motor for use as a CCW spare. However, Engineering Work Request S-A-ENG-99-007, Action Number 9, issued a temporary change to Procedure RMP 9006-4 on September 21, 1999. Therefore, it appeared that the procedure was updated to reference this second spare motor prior to the cancellation of SPEED 99-003, and that the procedure was not corrected after the SPEED was canceled. The inspectors also noted that the PBNP self-assessment earlier in 2003 had not identified this concern.

The failure to adequately control the reference to spare CCW motors in Procedure RMP 9006-4 was a violation of minor significance, not subject to enforcement action in accordance with Section IV of NRC's Enforcement Policy. The licensee documented this failure in CAP050398.

4.1.3.2 Equipment Performance

a. Inspection Scope

The inspectors evaluated the adequacy of the maintenance, operation, and testing of the CCW system. The inspectors reviewed CCW surveillance testing and calibration records, related CAPs, heat exchanger testing and inspection results, CCW system health reports, and CCW pump vibration and differential pressure trending data to determine if CCW system equipment was being adequately maintained, operated, and tested. The inspectors also reviewed CCW pump and valves surveillance testing and CCW surge tank lever switch calibration records to determine if the acceptance criteria were consistent with design basis requirements.

Heat exchanger performance testing results, the GL 89-13 ("Service Water System Problems Affecting Safety-Related Equipment," July 18, 1989) program document, related CAPs, and heat exchanger visual inspection results were also reviewed to assess whether heat exchangers were being maintained and operated per system design requirements. Radiography results for the EDG heat exchanger alternate supply were also reviewed to determine if CCW lines were being maintained and available.

Equipment performance-related CAPs, such as CAPs related to CCW pump vibration, valve stroke time testing, and surge tank level transmitter operation, were reviewed to determine if system operability was degraded and corrective actions were effective in maintaining system design.

b. Observations and Findings

Testing of Manual CCW System Valves

Introduction: The inspectors identified a finding of very low safety significance (Green) involving a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XI, "Test

Control." Specifically, the licensee failed to include in the inservice testing program manual CCW valves that were required to perform a safety function.

Description: The inspectors reviewed the resolution of CAP028946 written on August 5, 2002, during the NRC Safety System Design and Performance Capability Inspection (IR 50-266/02-09(DRS); 50-301/02-09(DRS)), in response to questions regarding the testing of manual CCW valves that were required in EOPs to be operated. The CAP indicated that the valves should not be included in the inservice testing (IST) program based on Section 4.4.6 of NUREG-1482, "Guidelines for Inservice Testing at Nuclear Power Plants," April 1985. Instead, the CAP recommended establishing a non-IST program to periodically cycle the valves. The valves in question were included in Attachment A of both EOP-1.3, "Transfer to Containment Sump Recirculation - Low Head Injection," Revision 30, and EOP-1.4, "Transfer to Containment Sump Recirculation - High Head Injection," Revision 10. After an accident, these valves were to be closed to isolate nonessential CCW loads and ensure adequate cooling water flow to the RHR heat exchangers.

The inspectors questioned this interpretation of NUREG-1482. In response, the licensee reevaluated the function of the valves and concluded that they were required to support the PBNP safety analysis. The licensee wrote CAP050340 on September 22, 2003, to address the omission of these valves from the IST program. In addition, the licensee prepared an OD on September 24, to address the capability of these valves to perform their safety function. This operability review verified that all but 1 of the 36 manual valves had been exercised within the previous 3 years or were normally closed. This provided reasonable assurance of operability. The inspectors noted that the PBNP self-assessment earlier in 2003 had not identified this concern.

Analysis: The failure to account for these valves in the IST program was more than minor because it affected the mitigating systems cornerstone. However, this finding screened as Green in the SDP Phase 1, Mitigation Systems, question 1, because the valves were considered capable of performing their safety function per GL 91-18.

Enforcement: 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," states, in part, that a test program shall be established to assure that all testing required to demonstrate that safety-related structures, systems, and components will perform satisfactorily in service is identified and performed in accordance with written test procedures. Contrary to this, the licensee failed to perform all testing required to demonstrate that components would perform satisfactorily in service. Specifically, several manual CCW valves that were required to perform a safety function were not included in the IST program. As a result, the potential existed that these valves could have failed to operate when required. After the identification of this issue by the inspectors, the licensee implemented appropriate corrective actions. The PBNP staff wrote CAP050340, entering this issue into the corrective action program.

Because of the very low safety significance of the finding and because the licensee had entered this issue into their corrective action program, it was considered a Non-Cited Violation, consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 50-266/03-07-11; 50-301/03-07-11).

4.1.4 Corrective Actions

a. Inspection Scope

The inspectors reviewed various corrective action program and engineering-specific documents and interviewed plant personnel to assess the effectiveness of corrective actions for deficiencies involving design of the 125-VDC and CCW systems specifically, and other systems in general.

b. Observations and Findings

The inspectors identified numerous, minor examples where corrective actions were not timely or thoroughly implemented or the issues for which corrective actions were taken were not thoroughly evaluated. Although these examples were not found to be significant or to result in operability concerns, they supported an observation by the inspectors that the engineering group was challenged by limited resources and competing priorities. Several of the examples are discussed below.

- Several CAPs were written as a result of the licensee's self-assessment of the 125-VDC system to address concerns with the lack of updated calculations. However, these CAPs did not address the larger issue of design basis and configuration control. Major modifications to the 125-VDC system were performed by the licensee even though no accurate, updated design basis calculations to support even the present configuration existed. This issue is discussed further in Section 4.1.1.1.b.2.

- A self-assessment of the emergency diesel generators identified that Calculation N-93-002 for degraded voltage analysis did not include acceptance criteria for the minimum alternating current (AC) input voltage to safety-related battery chargers. Subsequently, one battery charger was identified as having voltage below its specified rating, and factory test results were used to justify acceptable performance. However, a CAP was not written to identify and correct the inadequate acceptance criteria in the calculation. In response to the concern, CAP050211 was written but it cited the original evaluation of factory tests as a justification for operability. The inspectors noted that both the original assessment evaluation and the CAP assumed that the minimum voltage requirement for the battery chargers was 414 volts (V) (90 percent of 460 V). In response to the inspectors' inquiry, it was discovered that the actual rating of the chargers was 480 V so that the correct acceptance criteria should have been 432 V (90 percent of 480 V). This did not affect the previous evaluation of the charger, but upon further review of Calculation N-93-002, the licensee discovered that two other battery chargers (from a different manufacturer) also failed to meet the revised acceptance criteria by a small margin. The licensee then issued CAP050430 and provided a reasonable justification for the operability of these two battery chargers.

  The failure to include acceptance criteria in Calculation N-93-002 for the safety-related battery chargers was a violation 10 CFR Part 50, Appendix B, Criterion III, "Design Control." The failure to write a CAP upon the discovery of this omission and the use of inappropriate criteria to evaluate it were violations of 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action.” Although these issues should be corrected, they are minor and, thus, not subject to enforcement action in accordance with Section IV of the NRC’s Enforcement Policy. These issues were entered into the licensee’s corrective action program as CAP050211 and CAP050430.

- The licensee’s vendor failed to write a CAP to capture multiple (minor) drawing errors identified during the preparation of 125-VDC calculations. The vendor had accumulated a list of several dozen discrepancies over the period of several months but had failed to provide this list to the licensee or initiate other corrective action until questioned by the inspectors. Although this corrective actions issue should be corrected, it constitutes a violation of minor significance, not subject to enforcement action in accordance with Section IV of the NRC’s Enforcement Policy. The issue did indicate a weakness in the licensee’s vendor control and corrective action programs. The licensee subsequently wrote CAP050258 to address the specific drawing discrepancies.

- The PAB battery room and inverter rooms ventilation system was installed via modification M-784 in 1991. However, prior to the installation, changes to the design were approved involving the omission of thermostatically controlled solenoid valves. CAP000729 required revision to battery ventilation system drawings to reflect the as-built condition but was canceled due to an inappropriately classified corrective action, prior to the work being done. Although this corrective actions issue should be corrected, it constitutes a violation of minor significance, not subject to enforcement action in accordance with Section IV of the NRC’s Enforcement Policy. This issue did indicate a weakness in the licensee’s corrective action program. It was documented in CAP050096, which provided a new corrective action to revise the drawings.

  Also regarding the inverters, FSAR Section A.1-7 stated that during a station blackout event, the heatup of the instrument inverter rooms would reach a maximum temperature of 115 degrees Fahrenheit in 1 hour. This description did not match the most recent design basis heatup calculation associated with the inverter room which established a maximum temperature of 120 degrees in 1 hour. After questioning by the inspectors, the licensee initiated a CAP and determined that the FSAR was incorrect and needed revision.

- Inadequate Justification for Failure to Evaluate Replacement Motor Electrical Characteristics. The licensee failed to perform an adequate technical evaluation of a replacement motor after discovering that the original modification also failed to perform an adequate evaluation. Modification 97-107 installed an Appendix R spare CCW pump motor as a permanent replacement for the existing CCW pump motor. CAP031241 identified that the modification did not reference calculations that needed to be updated or discuss the differences in electrical parameters that were evaluated in SPEED 97-084. The SPEED evaluated the use of the motor as an Appendix R spare only. The justification in the CAP regarding operability of the motor discussed the non-conservative effects of the motor’s short circuit characteristics, and the improved full load current, but did not evaluate the larger starting current for the replacement motor. This parameter had an adverse impact on the starting voltage calculated in Calculation N-93-002 so it should have been evaluated in the CAP. In response to the inspectors' question, the licensee revised CAP031241 to evaluate the motor starting current, which the inspectors subsequently determined to be acceptable. Because the replacement motor was acceptable in its application, this failure to take the appropriate corrective action (conduct an adequate evaluation) constitutes a violation of minor significance, not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. The issue did indicate weaknesses in the licensee's corrective action and design control programs.

- Inadequate Procedures to Prevent Re-Racking of Breakers Following Failure to Operate on Demand. CAP031069 was written following failure of a safety-related breaker (a condition adverse to quality) but it did not identify a deficiency relating to re-racking prior to troubleshooting the cause of failure. Interviews with operators indicated that it was station policy to have maintenance perform troubleshooting before trying to operate a breaker that had failed to operate on demand, but that this policy had not been formalized in plant procedures. Re-racking a failed breaker could destroy information needed to ascertain the cause of the failure. When a breaker was racked into a switchgear cubicle, levers in the cubicle sensed the breaker position and repositioned contacts in control circuits for the breaker. If these switches failed to reposition properly due to misalignment of the breaker in the cubicle, re-racking may simply achieve the proper alignment and solve the problem. However, re-racking may also mask an intermittent failure in another part of the circuit, or prevent detection of excessive wear, or damage to the position switch mechanism. The breaker position switches could then fail in-service due to slight movement caused by operating the breaker, or experience a repeat failure of an unrelated circuit element.

  The licensee was not able to identify similar instances of re-racking failed breakers without troubleshooting so this failure to adequately identify and correct the problem with the breaker constitutes a violation of minor significance, not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. This issue represented weaknesses in station procedures for not prohibiting re-racking of failed breakers and in the corrective action program for not identifying an inadequate station practice. The licensee wrote CAP050390 to evaluate the issue.

- CAP049868 was written on September 4, 2003, for a weakness in an emergency diesel generator (EDG) transient loading calculation. Specifically, this CAP identified that a potentially incorrect value of 4160 V was used in the calculation for the initial starting voltage. Instead, the actual value used should have been the more conservative, and therefore bounding, value of 3744 V. The licensee originally asserted that the EDG was operable because of the successful completion of the 18-month functional test and that this issue was merely an administrative issue pertaining to the calculation.

The licensee identified that a review by a senior reactor operator had not even been obtained for this issue when it was initially assessed by the licensee. The licensee wrote CAP05348 to address this issue.

The inspectors questioned the validity of the operability determination and were concerned that an evaluation of adverse effects due to the lower voltage was needed to ensure operability. The major concern was the effects on voltage due to the block loading of engineered safety feature loads on the EDG with this new lower value for voltage (3744 V). The temporary voltage drop due to block loading would cause control circuit contactors to momentarily drop out until adequate voltage was recovered. The licensee stated that this issue was discussed when the CAP was initiated, but was not documented in the CAP. The concern with the calculation was being addressed through CE012276, “DG Loading Calculation Weakness.”

Although the equipment was determined to be operable, this issue is an example of an equipment deficiency that was inadequately resolved initially through the licensee’s corrective action program. The concern identified in the initial CAP was not properly resolved, and a formal OD was not performed. The issue constitutes a violation of minor significance, not subject to enforcement action in accordance with Section IV of the NRC’s Enforcement Policy.

- CAP028994, dated August 8, 2002, was written during the NRC Safety System Design and Performance Capability Inspection (IR 50-266/02-09(DRS); 50-301/02-09(DRS)) in response to inspectors’ questions regarding the duration of containment spray operation after a postulated accident. An operability determination was completed on August 9, 2002 and EWR026103 was initiated on August 16, 2002, to resolve the issue. However, at the time of this inspection (September 2003), the due date for this activity had been extended twice and the most recent entry in the CAP indicated that the activity would be reassigned when supplemental staff was hired. After completion of the current inspection, the licensee indicated that a meeting of engineering personnel was held in December 2003 to discuss the issue and CA054169 was subsequently written to update the calculation pertaining to the duration of containment spray operation. The due date for the corrective action was June 23, 2004, and appeared reasonable to the inspectors.

- CAP028992, dated August 8, 2002, was written, also during the NRC Safety System Design and Performance Capability Inspection, in response to inspectors’ questions regarding an inappropriate setpoint included in EOP 1.3, “Large Break LOCA,” Revision 27. During the 2002 inspection, Revision 28 was issued to remove the step containing the setpoint. However, EOP 1.4, “Small Break LOCA,” was issued with this setpoint still included. An operability determination, based on an informal analysis, determined that this setpoint did not result in an operability concern for a small-break LOCA. CA026038 was initiated on August 12, 2002, to formally analyze the issue and remove the setpoint from EOP 1.4. At the time of this inspection (September 2003), the due date for this activity had been extended several times and EOP 1.4 (Revision 10) still contained the inappropriate setpoint. After completion of the current inspection, the licensee indicated that EOP 1.4 had been revised to address the issue (the current revision of EOP 1.4 was 13).

- CE010524 was initiated on August 12, 2002, to perform an extent of condition review for the EOP 1.3 and EOP 1.4 issues. The scope of this activity indicated that an extensive review of both the EOP alignments and EOP setpoints were required. This activity was closed to CA026250, which was initiated on September 6, 2002. CA026250 stated that the scope was “significantly smaller than that originally proposed in the parent CAP.”

  This activity was extended twice, then completed by the nuclear oversight organization (quality assurance) on June 24, 2003. However, the scope of the review did not appear to include an extensive review of either the EOP alignments or the EOP setpoints. On August 12, 2002, CA026045 was initiated by design engineering to perform a similar EOP review. This activity was completed on September 9, 2003, after an extensive review of EOP 1.3 and EOP 1.4 alignments by a contractor. CA033093 was initiated to resolve several minor concerns identified by this review. However, none of these activities appeared to address EOP setpoints, as identified in the original scope. After completion of the inspection, the licensee indicated that a full review of the EOPs was being conducted per step 2.A of OP-14-005, “Validate and Integrate Calculations and Setpoints.”

- The inspectors reviewed the I&C Calculation Update Program Project Plan, Revision 0, dated June 6, 2003. This plan was associated with Excellence Plan action plan OP-14-005, “Validate and Integrate Calculations and Setpoints.” Section 1 of the I&C plan described problems associated with past programs implemented to establish design basis I&C calculations. This section stated, in part, that some of these initiatives were not fully implemented as financial and manpower resources were directed to other projects. Updates to design basis calculations were performed on a just-in-time, as-needed basis and other critical calculations have lain dormant for several years. Many calculations were never reviewed and approved, and others were maintained outside the design control process. The problems and issues discussed in the plan was consistent with the inspectors’ observations.

4.1.5 Procedure Quality

a. Inspection Scope

The inspectors evaluated the role of procedures in the performance deficiencies in corrective actions and engineering. Specifically, selected operating, maintenance, and testing procedures were reviewed to ensure the incorporation of appropriate design basis information.

The inspectors reviewed CAPs and surveillance and calibration procedures to ensure incorporation of appropriate design information. Specifically, the inspectors reviewed CCW surge tank lever channel calibration procedures, CCW pump and valves surveillance testing, and CCW heat exchanger performance testing data collection procedures. These procedures were reviewed to determine the technical adequacy of the acceptance criteria and that the CCW system was operated in accordance with system design.

Corrective action program documents related to inadequate procedures were reviewed to assess if corrective actions were effective and to ensure that the procedures were corrected. Specifically, the inspectors reviewed CAPs related to CCW pump post-maintenance testing procedures and procedure feedback backlog issues.

The inspectors also reviewed the resolution of CAP028998, written on August 8, 2002, in response to deficiencies identified in EOPs by the NRC during the NRC Safety System Design and Performance Capability Inspection (IR 50-266/02-09(DRS); 50-301/02-09(DRS)).

b. Observations and Findings

Introduction: The inspectors identified a finding of very low safety significance involving a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings." Specifically, the licensee failed to include appropriate quantitative setpoint values in plant EOPs. Two examples of non-conservative setpoint values were identified during the inspection.

Description: The inspectors reviewed selected EOPs and EOP setpoints and noted that the EOP setpoint basis document for the minimum low head safety injection B train flow (EOPSTPT L.3, Revision 1, dated March 25, 1992) appeared to contain an informal instrument uncertainty calculation. The inspectors questioned the accuracy of the EOP setpoint value of 275 gallons per minute (gpm) developed by this document.

In response to this question, the licensee investigated the L.3 EOP setpoint and found it to be non-conservative. The licensee stated that the L.3 setpoint value should have been 400 gpm. The 275-gpm value did not account for instrument uncertainties. In addition, the licensee investigated the EOP setpoint for the minimum low head safety injection A train flow (EOPSTPT L.13, Revision 0, dated March 25, 1992) and determined that it was also non-conservative. The 450-gpm L.13 setpoint value should have been 650 gpm to appropriately account for instrument uncertainties. The licensee identified 34 EOP steps that included these setpoint values, and wrote CAP050388 on September 24, 2003, to address this issue. The licensee determined that this was not an operability concern because these setpoint values were not the sole indication used to verify adequate safety injection flow. The CAP also stated that the potential for the discovery of this condition had been identified in Excellence Plan action plan OP-14-005, "Validate and Integrate Calculations and Setpoints."

Based on these examples, the inspectors questioned the timeliness of the extent of condition review associated with action plan OP-14-005, which was scheduled for completion by 2006. In response to this concern, the licensee wrote CAP050429 on September 25, 2003, to perform an extent of condition evaluation on all EOP setpoints and consider accelerating the appropriate steps of action plan OP-14-005.

The inspectors noted that the vendor calculation that addressed the instrument uncertainties associated with EOP setpoints L.3 (WEP-SPT-34a, Revision 0) had been approved by the licensee on April 30, 2000, but had not been incorporated into the EOP setpoint basis document or the EOPs. Discussions with licensee personnel indicated that the update of the EOP setpoint bases had not been completed due to resource limitations.

The inspectors also identified incorrect values in two other EOP basis documents (EOPSTPT V.14, Revision 1, dated November 29, 1994, and EOPSTPT V.35, Revision 0, dated November 29, 1994). In these cases, the actual EOP setpoint values agreed with the engineering analyses, but the EOP setpoint basis documents were incorrect. The licensee initiated CAP050192 on September 15, 2003, to address this issue.

Analysis: The failure to account for instrument inaccuracies for EOP setpoints was considered more than minor because it affected the mitigating systems cornerstone. However, this finding screened as Green in the SDP Phase 1, Mitigation Systems, question 1. Although this issue could have resulted in challenges to the operators, the inspectors considered the redundancy of flow indication adequate for system availability per GL 91-18.

Enforcement: Criterion V, “Instructions, Procedures, and Drawings,” of 10 CFR Part 50, Appendix B, states, in part, that instructions, procedures, or drawings shall include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished. Contrary to this, the licensee failed to include in procedures appropriate quantitative acceptance criteria for determining that important activities were satisfactorily accomplished. Specifically, several plant EOPs included non-conservative setpoint values. As a result, the operators could have isolated one train of low head safety injection flow while the other train was not providing adequate post-LOCA flow. After the identification of this issue by the inspectors, the licensee entered this finding into its corrective action program as CAP050388 and implemented appropriate corrective actions.

Because of the very low safety significance (Green) of the finding and because the licensee has entered this issue into its corrective action program, the failure of the licensee to include the appropriate setpoints in EOPs is considered as a Non-Cited Violation, consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 50-266/03-07-12; 50-301/03-07-12).

4.1.6 Human Performance

a. Inspection Scope

The inspectors evaluated the role of human performance attributes, such as group organization, training and qualifications, communications, and the human-system interfaces in the corrective action and engineering programs. This was accomplished through document review, interviews with plant staff and management, and attendance at various plant meetings, including the daily engineering department meeting. The inspectors evaluated a sample of corrective actions related to deficiencies involving human performance and identified one CAP regarding the leak-before-break analysis of record that warranted further review.

b. Observations and Findings

Of the CAPs that were reviewed for the 125-VDC system, none specifically identified human performance as a deficiency; therefore, no corrective actions for deficiencies involving human performance were identified. The inspectors noted that there appeared to be a propensity at PBNP to regard technical issues that result in CAPs as significant only if equipment was inoperable (an observation also noted during the corrective action phase of the inspection--see "Significance Level," in Section 2.1.b.3 of this report). As a result, some technical issues without immediate operability ramifications but with possibly important ramifications under slightly different circumstances appeared to be treated with less significance in the corrective action program. This would appear to be consistent with the observation that engineering issues do not seem to get as high a priority as they should merit.

The inspectors concluded that the daily morning engineering department meeting appeared to be effective. Again, it was apparent that the engineering department was focused on addressing emergent plant issues. However, this focus on emergent issues has resulted in long-term design engineering work, such as re-establishing an accurate and up-to-date design and licensing basis being treated as low priority work. By being primarily operations focused, the engineering department appeared to be in the habit of "putting out fires" rather than preventing the "fires" from occurring. The inspectors recognized that safe operation of the plant was the appropriate priority, but that maintaining the design bases of the plant also required attention to ensure that the plant was operated within design limitations.

Individual engineer work hours per week were limited to 72 hours, unless there was signed approval from the Director of Engineering to exceed this limit; based on interviews with engineers, the average work week was approximately 50 to 60 hours. However, as noted by the inspectors and in assessments of engineering done for the licensee in early 1998 and 2003, the engineering organization was often in a reactive mode because of a heavy work load.

b.1 Leak-Before-Break Analysis of Record

On June 16, 2003, the licensee wrote CAP033580 to address concerns related to the PBNP leak-before-break (LBB) analyses. The original plant design basis required consideration of the dynamic affects resulting from non-mechanistic breaks in class 1 piping systems. In addition, new industry concerns regarding asymmetrical blowdown loads were identified subsequent to the original PBNP design (NRC Unresolved Safety Issue A-2, "Asymmetric Blowdown Loads on Reactor Primary Coolant Systems"). This Unresolved Safety Issue was addressed by Westinghouse on a generic basis. The NRC reviewed and approved the generic Westinghouse LBB analysis (GL 84-04, "Safety Evaluation of Westinghouse Topical Reports Dealing With Elimination of Postulated Pipe Breaks in PWR Primary Main Loops," February 1, 1984) as a basis to remove (or not install) protection against asymmetrical dynamic loads. In 1986, the NRC stated that PBNP was bounded by the generic Westinghouse LBB analysis;

however, a plant-specific LBB analysis (WCAP-14439, Revision 0) was subsequently performed for PBNP Units 1 and 2 by Westinghouse. This analysis included parameters associated with the Unit 2 steam generator replacement, partial power uprate conditions, and a 40-year operating period.

The plant specific analysis was not submitted to the NRC for review and approval as required by 10 CFR Part 50, Appendix A, Criterion 4, “Environmental and Dynamic Effects Design Basis.” This plant specific analysis was credited in SER 96-084-02, “PBNP Unit 2 Replacement Steam Generator Design,” and SE 2001-0007, “Component Cooling System Closed Loop Inside Containment.”

CAP033580 evaluated the condition and, on June 17, 2003, incorrectly determined that NRC review and approval was not required for the plant-specific LBB analysis. On August 1, 2003, the licensee reevaluated the condition and determined that NRC review was required. As a result, OD OPR000072 was performed, and concluded that the reactor coolant systems of both Units were operable, but non-conforming. CAP034513 was initiated on August 1 to address the failure to recognize the NRC submittal requirement during the June 17, 2003, screening. CAP034513 concluded that this was a knowledge-based error, apparently due to reliance on a dated piece of correspondence rather than on the current regulatory requirements.

Based on discussions with PBNP personnel, the inspectors determined that the plant-specific LBB analysis (WCAP-14439, Revision 0) had not been submitted to the NRC at the time of the inspection. Instead, the licensee intended to submit Revision 1. The revised analysis incorporated parameters associated with the proposed full power uprate and a 60-year operating period. The licensee stated that it was working with Westinghouse to incorporate corrections into WCAP-14439, Revision 1, prior to the submittal. These activities were being tracked by OPR000072.

The licensee-identified failure to submit the plant-specific LBB analysis to the NRC for review and approval as required by 10 CFR Part 50, Appendix A, Criterion 4, constitutes a violation of minor significance, not subject to enforcement action in accordance with Section IV of NRC’s Enforcement Policy. The licensee documented the failure to submit the analysis in CAP034513.

4.1.7 Miscellaneous Issue - Appendix R Concern for Speed Controllers for the Charging Pumps

a. Inspection Scope

While reviewing corrective actions for the AFW/IA Red finding, the inspectors identified a finding related to Appendix R and the speed controllers for the three per Unit positive displacement charging pumps.

b. Observations and Findings

Introduction: The inspectors identified a Green, Non-Cited Violation of 10 CFR Part 50, Appendix R, III.L.1.c, for not ensuring adequate control air to the speed controllers for the charging pumps during a postulated Appendix R fire event requiring an alternative shutdown method.

Description: For certain postulated fire scenarios that required the use of an alternative shutdown method, instrument air to the charging pump speed controllers would be lost and the controllers would then fail to slow speed. For certain alternative shutdown scenarios, where only one charging pump was available, the pump was required to be operating in fast speed to ensure adequate makeup to the RCS.

A 12-pack of nitrogen bottles that were hard-piped to the speed controller instrument air header served as a backup. However, the capacity of the backup was 8 hours. As compensatory measures, the licensee staged a dedicated air compressor, electrical cables, hoses, and fittings so that if the postulated fire were to occur, operators could assemble the equipment and supply air to the controllers. These actions were necessary for the plant to maintain hot standby conditions.

The inspectors concluded that this compensatory measure was a repair activity required to maintain hot standby conditions, that is “hot standby repairs,” and as such were not allowed by 10 CFR Part 50, Appendix R.

Analysis: This failure to ensure that control air to the speed controllers for the charging pumps would be maintained during a postulated Appendix R fire event is a violation of 10 CFR Part 50, Appendix R, Section III.L.1.c. This finding is more than minor because if left uncorrected, the finding would become a more significant safety concern. Without control air available for the charging pump speed controllers, operators would not have been able to maintain adequate makeup to the RCS. However, the inspectors determined that even though the operators would have been challenged by this type of hot shutdown repair, the operators most likely could have performed the necessary actions to assemble the staged equipment (air compressor, electrical cables, hoses, and fittings) so that the temporary air compressor could supply the required control air to the charging pump speed controllers.

This violation had no significant impact on the cornerstone because it did not involve the impairment or degradation of a fire protection feature. Therefore, this finding was considered to be a Green finding.

Enforcement: 10 CFR Part 50, Appendix R, Section III.L.1.c states, in part, that alternative shutdown capability shall be able to achieve and maintain hot standby conditions for a pressurized water reactor (such as Point Beach).

Contrary to this, the licensee could not maintain hot standby conditions, because for an alternative shutdown scenario, control air to the charging pump speed controllers could have been lost. This could have resulted in insufficient makeup to the RCS. The results of this violation were determined to be of very low safety significance. Therefore, because this violation of 10 CFR Part 50, Appendix R, Section III.L.1.c, was captured in the licensee’s corrective action program (CAP050456), it was considered a Non-Cited Violation (NCV 50-266/03-07-13; 50-301/03-07-13) consistent with Section VI.A.1 of the NRC Enforcement Policy.

4.2 Operations

4.2.1 Control Room and In-Plant Observations

a. Inspection Scope

The inspectors performed extended observations of licensed operator crews on both operating Units over multiple shifts to assess whether the operators were proactive in assessing plant conditions that may have indicated a safety concern and effectively communicating these issues to engineering. The inspectors interviewed individual operators while onshift, observed responses to expected and unexpected annunciators, observed log taking activities, observed verbal communication methods, observed crews perform reactivity changes on both Units, and observed periodic testing of the gas turbine (the station blackout power source). The inspectors also accompanied auxiliary (non-licensed) operators on daily plant tours. The inspectors evaluated operator performance against requirements contained in station Procedures OM 1.1, "Conduct of Plant Operations, PBNP Specific," Revision 13, and NP 2.1.1, "Conduct of Operations," Revision 1. Additionally, the inspectors discussed expectations for the conduct of operations with operations department management.

b. Observations and Findings

No findings of significance were identified. In general, the performance of control room operating crews was in accordance with station procedures and department management expectations. Communications between operators and engineers on day-to-day issues was adequate. During interviews with operators, it was clear that the operators recognized some differences in the level of formality exhibited from crew to crew. These differences did not appear to be significant and the Shift Managers interviewed by the inspectors acknowledged the need to establish uniformity between the crews in regards to formality and control room conduct (the Shift Manager was the senior reactor operator who supervised the onshift crews of licensed and non-licensed operators).

4.2.2 Time-Critical Operator Actions

a. Inspection Scope

The inspectors reviewed actions taken by the licensee to validate time-critical operator actions (such as, operator response to a steam generator tube rupture, post-accident alignment of the RHR system, containment sump recirculation initiation time, and post-accident alignment of the containment fan coolers) as documented in Nuclear Plant Memorandum (NPM) 2003-0646, "Time-Critical Operator Actions." The inspectors reviewed EOPs, AOPs, the FSAR, and DBDs. The inspectors performed job performance measure (JPM)-style timed walk-downs of time-critical operator actions related to the restoration of safety-related battery chargers, response to Appendix R fires, operation of the gas turbine, switchover from refueling water storage tank injection to containment sump recirculation, and manual switchover from the condensate storage tank to the SW system for AFW system suction. The inspectors interviewed licensed and non-licensed operators and reviewed CAPs and ODs related to time-critical operator actions.

b. Observations and Findings

No findings of significance were identified. Overall, the licensee's review of time-critical operator actions was thorough and time-validation bases were well founded in the DBDs. The original charter from the Site Vice-President to the Time Validation Team (dated August 18, 2003) included a requirement to identify time-dependent maintenance actions that analyses were dependent on, such as replacement of a CCW pump for Appendix R or station blackout scenarios. However, the licensee team did not validate the availability and suitability of equipment staged to support safe shutdown of the reactor concurrent with a fire in the area of the CCW pumps. As a result, the licensee's Time Validation Team missed the opportunity to identify several issues later identified by the inspectors, including the failure to evaluate the locked rotor current and/or starting current requirements for a replacement CCW pump motor (as discussed in Section 4.1.3.5).

The inspectors' walkdowns indicated that required auxiliary equipment was available; required components, such as valves and breakers, were easily accessible; and times established for the completion of time-critical operator actions were realistic and achievable. However, the inspectors identified multiple examples of auxiliary equipment that was poorly labeled which could slow the operator's response times. The licensee wrote CAP050523 for the labeling issues. Efforts to improve equipment labeling were part of Excellence Plan action plan OP-13-002, "Equipment Label and Operator Aid Improvement."

4.2.3 System Walkdowns

a. Inspection Scope

The inspectors performed extensive walkdowns of the in-plant and main control room portions of the 125-VDC, CCW, and AFW systems. The inspectors reviewed the individual system electrical and mechanical lineups, the FSAR sections and applicable TSs for each system, and radiographs of AFW pump suction piping. The inspectors reviewed CAPs and open ODs regarding problems noted with these systems. The inspectors noted the material condition of system pumps, valves, and installed freeze protection (if applicable), as well as piping hangers and other supports. In the vicinity of these systems, the inspectors checked for unanalyzed flammable materials, general cleanliness and lighting, the condition of scaffolding, and the temporary storage of material and equipment.

The inspectors reviewed Procedures NP 2.1.4, "Operator Workarounds," Revision 1; OM 1.1, "Conduct of Plant Operations, PBNP Specific," Revision 13; NP 2.1.1, "Conduct of Operations," Revision 1; and OM 5.4.4, "Control of Posted Plant Information." The inspectors assessed the aggregate impact on control room operators imposed by alarms taken out of service, the posting of temporary instructions, open temporary modifications, and conditions resulting in operator burdens or workarounds. The inspectors reviewed the Operator Work Around Summary Report, minutes from periodic

Operator Work Around Meetings, the Operator Work Around Aggregate Impact performance indicator data contained in the Point Beach Nuclear Power Plant Performance Indicator Monthly Reports, and CAPs related to operator workarounds and burdens.

The inspectors reviewed EOPs and AOPs for "proceduralized" workarounds. Finally, the inspectors interviewed licensed operators, non-licensed operators, and operations department management. Efforts by the licensee to further reduce operator burdens, including workarounds, were captured in Excellence Plan action plan OP-13-001, "Reduce Total Operator Burden."

b. <u>Observations and Findings</u>

No findings of significance were identified. In general, the inspectors found that the 125-VDC, CCW, and AFW systems were aligned to support their safety functions and appeared to be of good material condition. During the walkdown of the AFW system, the inspectors noted that the licensee's Master Data Book had not been updated to reflect power supply changes made as a result of a recent modification to the differential pressure indicating switch (DPIS) power supplies that provide for "open" and "closed" indication for the AFW pump recirculation line isolation valves. The licensee wrote CAP050641 for this issue. Additionally, the inspectors identified an empty CCW system pump bearing oiler. The licensee refilled the oiler and wrote CAP050094 to determine why the oiler was not identified earlier.

The licensee appeared to effectively manage the aggregate impact of workarounds on control room operators. Operations department management were cognizant of current operator workarounds and sensitive to the need to monitor, prioritize, and workdown the total number. The licensee maintained several databases containing information regarding total numbers of equipment issues contributing to operator burdens and workarounds and appeared to be effectively managing the workdown of those lists. A review of CAPs indicated that the licensee was identifying workarounds and assigning appropriate corrective actions to minimize impact. The licensee's efforts appeared to be effective in minimizing the aggregate impact of workarounds on the control room operator's ability to operate the plant in a safe manner and in minimizing the impact on the operator's ability to respond to events.

The inspectors identified an example of a "proceduralized" operator workaround involving the cross-tie capability of the Unit 1 and Unit 2 CCW systems described in AOP-10B, "Safe to Cold Shutdown in Local Control," Revision 5. As originally designed, the CCW systems could be cross-tied by opening two valves: CC-722A (suction) and CC-722B (discharge). Because of a history of excessive seat leakage on CC-722B, AOP-10B was modified to cross-tie the discharge side of one CCW system directly at the CCW heat exchangers; requiring the opening of five valves instead of one. The licensee wrote CAP050465 to address this inspector-identified proceduralized workaround.

4.2.4 Operator Interactions with Engineering and Maintenance Personnel

a. Inspection Scope

The inspectors reviewed ODs and CAPs and interviewed operations and engineering personnel to determine if operations, engineering, maintenance, and affected support groups were involved in evaluation and concurrence process for approving: (1) performance of non-routine maintenance activities, (2) temporary modifications, and (3) field change requests.

The inspectors reviewed a sample of planned and emergent on-line maintenance activities including readjustment of current limiters in the safety-related battery chargers. The inspectors also reviewed currently open temporary modifications; reviewed station Procedure NP 7.3.1, "Temporary Modifications," Revision 13; and a sample of recently installed permanent plant modifications made to the AFW system.

b. Observations and Findings

No findings of significance were identified. Operations department communications and interaction with the engineering department appeared to be effective for dealing with day-to-day and emergent equipment availability or operability issues. No problems were noted with the involvement of operations, engineering, maintenance, and affected support groups in evaluation and concurrence process for approving: (1) performance of non-routine maintenance activities, (2) temporary modifications, and (3) field change requests.

4.2.5 Distribution of Temporary Changes to EOPs

a. Inspection Scope

During the special inspection to review the AFW orifice plugging issue (IR 50-266/02-15(DRP); 50-301/02-15(DRP), a problem was identified regarding the inadequate distribution of temporary changes of EOPs to the appropriate emergency response facilities. The operations department, as the owner of the EOPs, was responsible for determining the distribution of temporary changes. During the current inspection, the inspectors reviewed recent changes made to EOPs (and AOPs) to ensure controlled copies of these documents in various emergency response facilities were updated as required. The inspectors reviewed station Procedure NP 1.2.3, "Temporary Procedure Changes," Revision 12, and NP 1.1.3, "Procedure Preparation, Review, and Approval," Revision 12. The inspectors also reviewed CAPs documenting previous issues regarding untimely or incomplete incorporation of changes for EOPs and AOPs.

b. Observations and Findings

No findings of significance were identified. The licensee appeared to be effectively incorporating temporary and permanent changes to AOPs and EOPs into controlled copies of these procedures in the various emergency response facilities.

4.3 Maintenance

4.3.1 Maintenance Work Control

a. Inspection Scope

The inspectors reviewed the licensee's process for planning work, including the assessment of risk and the inclusion of new emergent work into the schedule. Also reviewed was the licensee's approach for reviewing aggregate risk of long-term deficiencies, such as tagouts, control room deficiencies, and operator workarounds.

The inspectors also evaluated the licensee's methodology for ensuring component out-of-service time with respect to updating the Probabilistic Risk Assessment (PRA).

b. Observations and Findings

The inspectors reviewed the licensee's 12-week cycle schedule and determined that it adequately grouped plant systems into a rotating set of work weeks based on the intervals for performing TS surveillances. At least weekly, the installed temporary modifications, operator workarounds, control board deficiencies, and lit annunciators were reviewed to ensure these items were scheduled as soon as practical. Risk assessments, using Safety Monitor, were performed at 5 weeks prior, 2 weeks prior, and immediately prior to the start of the execution week to ensure maintenance did not elevate risk unnecessarily, determine risk categories, and develop appropriate compensatory measures prior to performing work activities. Proposed work week schedules were compared with the actual completed work week to evaluate the actual risk level compared to the average and for a lessons-learned opportunity. Overall, the control of plant risk and configuration were appropriately controlled using risk insights to minimize the plant's aggregate risk.

The inspectors also reviewed a sampling of emergent maintenance activities and determined that the activities were adequately planned and controlled to avoid causing initiating events to occur or affect the functional capability of mitigating systems.

The plant highlighted the aggregate impact of items such as operator workarounds, temporary modifications, and control board deficiencies during the Plan of the Day meeting. Using the PRA, total system deficiencies in these categories were given a relative importance. The report effectively highlighted the impact of these somewhat less-significant items.

The inspectors reviewed the operational performance history for selected components in the 125-VDC and CCW systems and compared it with the assumed out-of-service times in the licensee's updated PRA. The licensee appropriately used component failure rates and test and maintenance unavailabilities developed from plant-specific data and generic nuclear industry data. Similar to industry practices, the licensee updated the PRA model every 3 years. The licensee's upgrade of the PRA model was part of Excellence Plan action plan OP-13-003, "Probabilistic Risk Assessment (PRA) Program Upgrade." The inspectors determined that the licensee's PRA group was very knowledgeable and was actively involved in assessing day-to-day plant operations and emergent issues with respect to the impact of these activities on the plant risk model.

4.3.2 Equipment Performance for the 125-VDC, CCW, and AFW Systems

a. Inspection Scope

The inspectors reviewed maintenance rule (10 CFR 50.65) scoping information for the 125-VDC, CCW, and AFW systems and compared it to the safety functions of each system as described in the DBDs. The inspectors reviewed the current maintenance rule designations ((a)(1) or (a)(2)) for the above systems. The inspectors reviewed a sample of CAPs documenting equipment problems with the systems and compared the information to current licensee listings of problems considered to constitute maintenance rule or maintenance preventable functional failures for each system.

The inspectors reviewed a sample of corrective actions taken for documented equipment problems to ensure actions taken were commensurate with the problems identified.

b. Observations and Findings

No findings of significance were identified.

4.4 Extension of the Engineering, Operations, and Maintenance Inspection

a. Inspection Scope

On September 24, 2003, while reviewing information to respond to a question from the inspectors, the licensee identified concerns with the closure in early 2003 of an operability determination (OPR 000040, AFW Pump Silting Due to SW Debris, Revision 1). This OD had been written in January 2003 during the AFW orifice plugging special inspection (IR 050050-266/02-15(DRP); 50-301/02-15(DRP)) after the licensee identified that a turbine-driven AFW (TDAFW) pump failed in 1974 after being operated with service water. As documented in CAP050404, “Concerns With Closure of OPR 00040 Rev 1 (AFW Pump Silting Due to SW Debris),” the licensee identified four issues: 1) The operability determination was closed with the non-conformance described in the operability determination still in existence since the compensatory measures were not evaluated for use as permanent Appendix R compliance strategies; 2) In an alternate shutdown scenario, the compensatory measures needed to ensure availability of the TDAFW pumps would not have been available to the operators; 3) Revisions 0 and 1 OPR 000040 identified two corrective actions involving increased reliability and potential improvements; however, no actions were found tracking resolution of these issues; and 4) The feasibility of the compensatory measures described in Revision 1 of OPR 00040 which were to be taken to ensure condensate-grade water was available following exhaustion of the CST water supply was not fully documented. Since these four concerns were identified by the licensee in response to the inspectors’ questions, and the resultant questions regarding the ability of the AFW system to perform its safety function, the IP 95003 inspection was extended a week from September 29,2003, to October 3, 2003.

During the additional week of inspection, the inspectors focused on the following areas related to the AFW system:

- Adequacy of operability determination
- Verify completion of AFW corrective actions: procedures, physical plant changes
- Adequacy of AFW corrective actions
- Assess timeliness of planned AFW corrective actions, plant modifications, RCE corrective actions, and excellence plan items.
- Assess overall operability of AFW system.

The inspectors reviewed selected procedures, corrective action program documents, operability determinations, and drawings; interviewed engineering, operations, and maintenance personnel; and conducted a detailed walkdown of the AFW system. These actions were in addition to those actions taken by the inspectors during the review of AFW issues during the corrective action phase of the IP 95003 inspection and in the as-scheduled engineering, operations, and maintenance phase.

b. Observations and Findings

b.1 Adequacy of Operability Determination

The inspectors reviewed open operability evaluations related to the AFW system, reviewed the disposition of related CAPs, and reviewed the recently approved 50.59 evaluation on operating the AFW system with new orifices. In addition, the inspectors verified that compensatory measures identified in “degraded but operable” evaluations were adequate and that these actions could be performed. Based on review of licensee documents and discussions with licensee engineering and operations staff, the inspectors determined the following:

- The revised operability determination regarding the 1974 TDAFW pump silting issue (OPR 82, Revision 1) was considered to be much improved in providing the support documentation and engineering judgement needed to determine operability without the compensatory measures with respect to Appendix R concerns. Inspectors reviewed SW pipe radiographs and agreed that the condition of the SW system in 2003 was much different and improved with respect to the amount of sand/silt contained in the system. Implementation of the GL 89-13 program, which included monthly flushing, accounted for much of the credit in minimizing the amount of debris in the SW system.
- In addition, other AFW-related operability determinations reviewed provided adequate engineering analysis to support operability.

b.2 Verify Completion of AFW Corrective Actions: Procedures, Physical Plant Changes

The inspectors conducted in-plant inspections and reviewed licensee documentation to validate that completed corrective actions related to AFW have actually been accomplished. Based on review of licensee documents and inspections the inspectors determined the following:

- AFW system procedures and changes to procedures supporting modifications that were reviewed appeared to be appropriately implemented or were being tracked to ensure completion.

- Outstanding AFW modifications were reviewed and determined to be adequately dispositioned and appropriately scheduled. In fact, the modification to repower one of the SW MOVs to AFW was rescheduled to be completed approximately 6 months earlier than originally scheduled.

- The 50.59 evaluation regarding the full implementation of the new recirculation line orifices was reviewed and determined to be adequate. Shift briefings were considered appropriate based on review of the briefing package and attendance at the briefings.

b.3 Adequacy of AFW Corrective Actions

The inspectors conducted in-plant inspections and reviewed licensee documentation, including a sample of approximately one-hundred corrective action documents (CAPs), to validate that planned and completed corrective actions related to the AFW system provided reasonable assurance that the problems have been adequately addressed. Based on review of licensee documents and inspections, the inspectors determined the following:

- CAPs reviewed did not identify any significant instances where AFW corrective actions were not complete or inappropriate. However, the licensee did identify instances of incomplete corrective actions during a review of corrective action documents performed in response to the issues identified in CAP050404. CAPs with incomplete corrective actions were identified in many disciplines (i.e., training, operation procedures, and engineering). These incomplete corrective actions, which involved primarily administrative issues, did not impact the operability of the AFW system. The inspectors determined that the quality review and closure of CAPs was an area needing improvements.

b.4 Timeliness of Planned AFW Corrective Actions, Plant Modifications, RCE Corrective Actions, and Excellence Plan Items

The inspectors reviewed licensee documentation, including related Excellence Plan action items, modifications, and CAPs associated with the AFW “Red” finding root cause evaluations to validate that these actions were scheduled to be completed in a reasonable time. Based on review of licensee documents, the inspectors determined the following:

- As discussed in Sections 2.1, 4.1.1.1.b, and 4.1.5 of this report, the inspectors were concerned with some Excellence Plan completion dates with respect to corrective actions associated with the AFW significant findings root cause evaluations and design basis calculation and setpoint reviews. In particular, the inspectors noted that the AFW system Issue Manager was not cognizant of the concerns regarding AFW operability documented in CAP050404 until notified by the inspectors several days after the CAP was issued. The inspectors determined that the lack of Issue Manager involvement in initially resolving this issue was due in part to the lack of documented guidance on Issue Manager responsibilities (Section 2.1.b.2).

b.5 Assess Overall Operability of AFW System

The inspectors conducted in-plant inspections, including a detailed AFW system walkdown. In addition, the inspectors reviewed licensee documentation, including the results of recent licensee self-assessment efforts focused on AFW operability. Based on review of licensee documents and inspections, the inspectors determined the following:

- Hand-over-hand AFW walkdowns (mechanical and electrical) verified agreement between plant drawings and the current system configuration. Also, recent modifications to the AFW system were observed and appeared to be installed in accordance with modification packages. The inspectors did not identify any significant issues that challenged the licensee's determination that the AFW system was operable.

c. Conclusions

Based on the results of the additional week of inspection focused on AFW system operability, the inspectors determined that the AFW was capable of performing its required safety functions. In addition, the licensee established 11 teams to review the following areas related to AFW system operability: operability determinations, AFW procedures and surveillance's, corrective action documents, electrical and mechanical modifications, independent assessment results, work orders, AFW pump silt operability verification, improved TS impact, Appendix R and compensatory measures, and training. The inspectors reviewed some of the results of the licensee's reviews and determined that the reviews were comprehensive. The inspectors determined that extensive licensee effort was needed to verify that the AFW system was operable because previous efforts in this area were either poorly implemented or documented. The licensee's failure to clearly demonstrate the operability of AFW system until an extensive review was conducted reflects on several performance areas needing improvement, including corrective action implementation and organizational effectiveness. In the area of corrective action implementation, the licensee's failure to complete corrective actions associated with Revision 1 of OPR 00040 (AFW Pump Silting Due to SW Debris) resulted in the operability of the AFW system being questioned. In addition, though the licensee created the Issue Manager position as a corrective action for the AFW RED findings, the poor implementation of this initiative rendered the Issue Manager as only partially effective in tracking and coordinating the resolution of AFW issues. In the area of organizational effectiveness, poor communication and coordination between engineering and operations staff resulted in corrective actions being ineffectively implemented, including Appendix R compensatory measures not being fully implemented. Though the inspectors concluded that the AFW system was operable, extensive inspection effort was required to verify that previous licensee corrective actions adequately addressed historic AFW system performance problems due to the inconsistent quality of the licensee's documentation and implementation of corrective actions.

4.5 Conclusion of the Engineering, Operations, and Maintenance Phase of the IP 95003 Inspection

The engineering organization was often in a reactive mode because of a heavy work load, a condition that has persisted since at least early 1998, when an assessment was performed of the Milwaukee-based design engineering group for the licensee. The high engineering work load was exacerbated by a loss of electrical system design information and experienced personnel when the design function was moved from Milwaukee to the site several years ago (1998-1999) and by turnover in plant management, particularly engineering upper management, in the past several years. Design engineering issues, including the existence of longstanding operability determinations, inexperienced staff engineers, and the reliance on out-of-date, inaccurate, or incomplete calculations, were identified during the review of the AC and 125-VDC systems.

Problems with individual calculations and control of calculations in general were previously identified by a third-party assessment early in 1998 and in 2003, and by the licensee's self-assessment in mid-2003. Confirmatory calculations by the inspectors confirmed that the electrical systems, which were relatively robust, were operable. Similar problems were not identified during the review of CCW, AFW, and other systems; however, several examples were identified by the inspectors of incorrect or narrowly focused evaluations by engineers of issues in the corrective action program. For AFW in particular, these corrective action problems resulted in the inspection being extended an additional week for the inspectors to gain assurance that the system was operable. The inspectors confirmed that based on their review of licensee documentation, various independent calculations, and system walkdowns, the 125-VDC, CCW, and AFW systems were operable and capable of performing their safety functions.

The inspectors found the operations and maintenance programs that were reviewed to be adequate. The operations/engineering interface warranted additional licensee attention.

5. Licensee-Identified Violation

The following violation of very low safety significance (Green) was identified by the licensee and is a violation of NRC requirements which meets the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as a Non-Cited Violation.

Failure To Declare An NOUE In a Timely Manner

10 CFR 50.54(q) requires, in part, that licensees follow and maintain in effect emergency plans which meet the standards in § 50.47(b) and the requirements in Appendix E of Part 50. 10 CFR 50.47(b)(4) states, in part, that a standard emergency classification and action level scheme will be in use. Appendix E, paragraph IV.D.3, states, in part, that a licensee shall have the capability to notify responsible State and local governmental authorities within 15 minutes after declaration of an emergency. EPIP 1.2, "Emergency Classification," Step 5.1.5, NOTE states that "classifications are to be made consistent with the goal of 15 minutes once plant parameters reach an Emergency Action Level (EAL), are first indicated in the Control Room." Contrary to this, on March 4, 2002, the licensee took approximately 31 minutes to notify responsible State and local governmental authorities of a liquified propane gas leak which met the criteria for declaration of an NOUE given in EAL 6.3.1.1, "A toxic or flammable gas release in or near the Protected Area." The licensee entered this failure to timely notify in their corrective action program as CAP034652. The violation is considered to be of very low safety significance because the state and local authorities were notified of the event and there was no affect on protective action recommendations to the public.

6. Management Meetings

Exit Meeting Summary

The inspectors presented the preliminary results of the inspection to Messrs. M. Sellman, P. Cowan, D. Cooper, A. Cayia and other members of licensee management on November 17, 2003. The licensee acknowledged the findings presented. No information reviewed during the inspection and likely to be included in the inspection report was identified as proprietary.

On December 16, a public exit meeting was held at the Holiday Inn in Manitowoc, Wisconsin, with Messrs. Cowan, Cooper, and Cayia and other members of licensee management to discuss the results of the inspection. The licensee acknowledged the findings presented. A summary of the meeting, a list of principal NRC and NMC attendees, and copies of the overhead slides used at the meeting were issued in a letter dated December 31, 2003.

On January 13, 2004, a predecisional enforcement conference was held to discuss the apparent violation regarding the EALs. A summary of that meeting and the results of the NRC's enforcement deliberation regarding that apparent violation will be issued in separate correspondence.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

R. Amundson	Operations Training Specialist
G. Arent	Kewaunee/Point Beach Regulatory Affairs Manager (former)
A. Cayia	Site Vice-President
J. Connolly	Regulatory Affairs Manager
J. Cowan	Senior Vice-President - Operations (NMC)
D. Fadel	Engineering Director (former)
F. Flentje	Senior Regulatory Compliance Specialist
J. Flessner	Engineering Projects Supervisor (Root Cause Team Leader)
D. Hettick	Performance Improvement Manager
R. Hopkins	Kewaunee-Point Beach Oversight Supervisor
J. Jensen	Plant Manager (former)
T. Kendall	Engineering Analysis Supervisor
J. Masterlark	PRA Engineer
J. McCarthy	Site Director
R. Milner	Emergency Preparedness Manager
L. Peterson	Engineering Projects Manager
K. Peveler	Kewaunee-Point Beach Nuclear Oversight Manager
S. Pfaff	Corrective Action Program Supervisor
J. Pruitt	Nuclear Oversight Assessor
M. Reddemann	NMC Vice-President - Engineering
E. Schmidt	AFW System Engineer
D. Schoon	Training Manager
J. Schweitzer	Engineering Director
P. Smith	Operations Training Coordinator
J. Strharsky	Production Planning Manager
T. Vandenbosch	EOP Coordinator
R. Wood	Engineering Programs Supervisor
T. Taylor	Site Assessment Manager
S. Thomas	Radiation Protection Manager
T. Webb	Regulatory Affairs Manager
E. Weinkam	NMC Director of Regulatory Services
W. Zipp	System Engineering Supervisor

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-266/03-07-01 50-301/03-07-01	NCV	10 CFR 50.54(q) and 10 CFR 50.47(b) Violation For Failure To Assign Adequate Emergency Response Organization Staffing. (Section 3.2.b.2)
50-266/03-07-02 50-301/03-07-02	NCV	10 CFR 50.9 Violation For Failure To Report In The Third Quarter Of 2001 That The Emergency Response Organization Performance Indicator Crossed The Significance Threshold From Green To White. (Section 3.2.b.3)
50-266/03-07-03 50-301/03-07-03	NCV	10 CFR 50.54(q) and 10 CFR 50.47(b) Violation For The Failure To Develop And Implement A Training Program For The Emergency Planning Staff. (Section 3.5)
50-266/03-07-04 50-301/03-07-04	URI	A Range Of Protective Action Recommendations Was Not Established For State And Local Governmental Authorities. (Section 3.6.b.1)
50-266/03-07-05 50-301/03-07-05	AV	10 CFR 50.54(q) and 10 CFR 50.47(b) Apparent Violation For Failure To Maintain A Standard Scheme of Emergency Action Levels. (Section 3.6.b.2)
50-266/03-07-06 50-301/03-07-06	NCV	10 CFR 50.54(q) and 10 CFR 50.47(b) Violation For Failure To Ensure That The Facility Seismic Monitors Could Support NOUE Declaration. (Section 3.6.b.3)
50-266/03-07-07 50-301/03-07-07	NCV	Design Control Violation For The Failure To Assure That The Regulatory Requirements And The Design Basis Were Accurately Maintained For The Battery Chargers. (Section 4.1.1.1.b.1)
50-266/03-07-08 50-301/03-07-08	NCV	Design Control Violation For The Failure To Revise Voltage Drop Calculations. (Section 4.1.1.1.b.2)
50-266/03-07-09 50-301/03-07-09	NCV	Corrective Action Violation For Untimely Correction of Equipment Not Environmentally Qualified. (Section 4.1.2.b.2.1)
50-266/03-07-10 50-301/03-07-10	NCV	10 CFR 50.49(f) Violation For Equipment Not Environmentally Qualified. (Section 4.1.2.b.2.2)
50-266/03-07-11 50-301/03-07-11	NCV	Test Control Violation For Not Including Several Manual CCW Valves In The Inservice Testing Program. (Section 4.1.3.2)
50-266/03-07-12 50-301/03-07-12	NCV	Inadequate Procedure Violation For Inaccurate Setpoints in EOPs. (Section 4.1.5)

50-266/03-07-13 50-301/03-07-13	NCV	Appendix R Violation For Failure To Ensure Air Would Be Available to Charging Pumps. (Section 4.1.7)

Closed

50-266/03-07-01 50-301/03-07-01	NCV	10 CFR 50.54(q) and 10 CFR 50.47(b) Violation For Failure To Assign Adequate Emergency Response Organization Staffing. (Section 3.2.b.2)
50-266/03-07-02 50-301/03-07-02	NCV	10 CFR 50.9 Violation For Failure To Report In The Third Quarter Of 2001 That The Emergency Response Organization Performance Indicator Crossed The Significance Threshold From Green To White. (Section 3.2.b.3)
50-266/03-07-03 50-301/03-07-03	NCV	10 CFR 50.54(q) and 10 CFR 50.47(b) Violation For The Failure To Develop And Implement A Training Program For The Emergency Planning Staff. (Section 3.5)
50-266/03-07-06 50-301/03-07-06	NCV	10 CFR 50.54(q) and 10 CFR 50.47(b) Violation For Failure To Ensure That The Facility Seismic Monitors Could Support NOUE Declaration. (Section 3.6.b.3)
50-266/03-07-07 50-301/03-07-07	NCV	Design Control Violation For The Failure To Assure That The Regulatory Requirements And The Design Basis Were Accurately Maintained For The Battery Chargers. (Section 4.1.1.1.b.1)
50-266/03-07-08 50-301/03-07-08	NCV	Design Control Violation For The Failure To Revise Voltage Drop Calculations. (Section 4.1.1.1.b.2)
50-266/03-07-09 50-301/03-07-09	NCV	Corrective Action Violation For Untimely Correction of Equipment Not Environmentally Qualified. (Section 4.1.2.b.2.1)
50-266/03-07-10 50-301/03-07-10	NCV	10 CFR 50.49(f) Violation For Equipment Not Environmentally Qualified. (Section 4.1.2.b.2.2)
50-266/03-07-11 50-301/03-07-11	NCV	Test Control Violation For Not Including Several Manual CCW Valves In The Inservice Testing Program. (Section 4.1.3.2)
50-266/03-07-12 50-301/03-07-12	NCV	Inadequate Procedure Violation For Inaccurate Setpoints in EOPs. (Section 4.1.5)
50-266/03-07-13 50-301/03-07-13	NCV	Appendix R Violation For Failure To Ensure Air Would Be Available to Charging Pumps. (Section 4.1.7)

Discussed

50-266/03-02-02 50-301/03-02-02	URI	Emergency Planning Organization 10 CFR 50.54(q); Technician Instructions, Procedures, And Drawings; Emergency Response Facility Equipment Replacements Without Licensee Knowledge; And Remote Emergency Notification Telephone System Monitoring Capability Issues. (Section 3.3)

LIST OF DOCUMENTS REVIEWED

CORRECTIVE ACTION PROGRAM

Corrective Action Program Documents

ACE001251, SOER 02-04 Evaluation: Underground Cables - Water Intrusion

CA030587, Excellence Plan - ACE & CE Skills, June 6, 2003

CA052332, Review Due Date Associated With CA029836 (From RCE 202), September 15, 2003

CAP002220, Procedure Marked Up, February 15, 2002

CAP002777, Untimely Corrective Actions - Failure to Establish Qualification Files for Equipment Credited for Operating in a High Energy Line Break (Operability Determination 98-0164), April 8, 2002

CAP002968, Work Performed on SI-878B While Valve Was Energized, April 22, 2002

CAP026410, AOP-9A Has Little Guidance for System Blockage, September 21, 2002

CAP028270, Inadequate Procedure Temp Change Process, May 20, 2002

CAP029952, Possible Common Mode Failure of Aux Feed Recirculation Lines, October 29, 2002

CAP030002, PBNP Facility Not Prepared For Cold Weather on 1 November 2002, November 5, 2002

CAP030040, Power Supply to AFW Pump Recirc Valves not Safety Related, November 7, 2000

CAP030236, SGTR Timing Scenario Results, November 25, 2002

CAP030664, Corrective Actions Not Timely, January 9, 2003

CAP031858, OPR-000038 Failed to Address Two Issues, March 27, 2003

CAP031860, NP 5.3.1 Requirement for CAQ Issue Resolution, March 27, 2003

CAP031894, Validation of New Manual Operator Actions Credited as Compensatory Measure, March 28, 2003

CAP033062, Improvements for NOS Processes Identified in Self-Assessments, May 23, 2003

CAP033681, NOS Self-Assessment PBSA-NOS-03-03 Improvement Item Assessment Process, June 20, 2003

CAP033889, Unit 1 Flux Map Detectors Failing, July 2, 2003

CAP033997, Unit 2 Main Feed Pump Trip Results in a Unit 2 Reactor Trip, July 10, 2003

CAP034489, Management Exception Evaluation Omitted Some CA Items, August 1, 2003

CAP034564, CA Items Outside Expected Completion Dates Require Detailed Review for Approvals, August 5, 2003

CAP034566, Low Amount of Site Data to Perform trending on HU [Human Performance], Process and Organization/Management Issues, August 5, 2003

CAP034598, No Documented Justification For Non-Performance of RCEs For Level A CAPs, August 6, 2003

CAP034626, MR 03-0656 Design Description Doesn't Reference Foxboro CIM, August 3, 2003

CAP050026, Corrective Action Due Date Extension Not Properly Approved, September 9, 2003

CAP050060, CAPs Not Initiated on QRT Reviews Graded as 3, September 10, 2003

CAP050108, Review Due Date Associated With CA029836 (From RCE 202), September 11, 2003

CAP050114, AFW RCE202 Requires a Revision, September 11, 2003

CAP050120, Management Support of the DRB, September 11, 2003

CAP050143, The Quality Review Team Has Not Been Effectively Implemented, September 12, 2003

CAP050177, 95003 EOM [Engineering, Operations, and Maintenance] Inspection Technical Debrief CAP Issues, September 15, 2003

CAP050350, Perform New Review of AFW System to Support Recirc AOV Safety Function Upgrade, September 23, 2003

CAP050509, Incorrect Closure of CAP 32355, September 29, 2003

CAP050590, Apparent Lack of Guidance for Duties and Responsibilities of an Issue Manager, October 1, 2003

CAP AR Screen Team - Screening Process, Revision 2

CAP Meeting Schedules

CAP Trend Code Manual, January 17, 2003

CARB Agenda for Tuesday, August 5, 2003 at 1:00PM

CARB Charter

CARB Training

Condition Evaluation and Apparent Cause Evaluation Techniques

Corrective Action Program User Aid - CA Closure Guide, June 2003

RCE000044, U2 Safety Injection Pump "Gas Bound" During Routine Preventive Maintenance, April 13, 2002

RCE000051, Untimely Corrective Action - Failure to Establish Qualification Files for Equipment, June 13, 2002

RCE000179, PB Corrective Action Program Performance Indicator Turned RED, June 13, 2002

RCE000182, U2R25 Maintenance Valve Team Personnel Repack a Non-Electrically Isolated Motor Operated Valve, August 26, 2002

RCE000191, Possible Common Mode Failure of Aux Feed Recirculation Lines, April 10, 2003, Revision 1

RCE000192, PBNP Facility Not Prepared For Cold Weather on 1 November 2002, May 14, 2003

RCE000202, Potential AFW Pump Damage Due to Low Flow that Results in Increase Core Damage Frequency, April 9, 2003

RCE000205, Unit 1 Flux Map Detectors Failing, September 15, 2003

RCE000206, Unit 2 Main Feed Pump Trip Results In a Unit 2 Reactor Trip, July 11, 2003

RCE 01-069, Increase CDF in AFW PRA Model Due to Procedural Inadequacies Related to Loss of Instrument Air, February 28, 2002

RCE Casual Assessment Guideline

RCE Certification Card

RCE Team Lead Certification Card

Drawings

Drawing EAPK00000317, Single Line Diagram Station Connections, June 28, 2003

Drawing EDCK00000142, Single Line Diagram 125V DC Dist. System, December 22, 2001

Drawing EDCK00000215, Single Line Diagram 125 Volt D. C. System, July 14, 2001

Drawing EDCK00000303, Single Line Diagram 125V DC System (Non-1E), June 18, 2003

Drawing EDCK00000402, Single Line Diagram 125V DC Dist, System, January 20, 1996

Drawing EDGK00000112, Logic Diagram Emergency Generator Starting, August 5, 2000

Drawing EDGK12800105, Train B Emergency Generator Starting, August 12, 2000

Procedures

AM 3-15, Work Control Manual

1ICP 04.003-5, Auxiliary Feedwater Flow Instruments Outage Calculations, July 30, 2002

ESG 1.7, Expectations for Use of Human Performance Tools in Engineering, July 17, 2003

ESG 1.8, Engineering Human Performance Improvement Team Charter, June 20, 2003

NP 1.1.3, Procedure Preparation Review and Approval, Revision 17

NP 1.6.5, Plant Operations Review Committee and Qualified Reviewer, August 6, 2003

NP 5.3.1, Action Request Process, April 23, 2003

NP 5.3.2, Industry Operating Experience Review Program, November 12, 2002

NP 5.3.3, Incident Investigation and Post Trip Review, February 12, 2003

NP 7.1.7, Quality Review Team, Revisions 0 and 1

NP 7.2.1, Plant Modifications, March 12, 2003

NP 7.3.1, Temporary Modifications, June 26, 2002

NP 9.3.3, Spare Parts Equivalency Evaluation, April 3, 2002

NP 10.2.4, Work Order Processing, June 4, 2003

ESC-030LP012, Equipment Failure Root Cause Analysis, June 4, 2003

FP-T-SAT-60, SAT Overview Procedure, June 13, 2003

OEG 001, Root Cause Evaluation, June 28, 2002

OEG 005, Equipment Root Cause Evaluation, June 13, 2003

OR 2003-002-3-031, Management Systems, June 8, 2003

ORI-01-LPARP, Action Request Process, June 11, 2003

Control of PBNP IP 95003 Inspection Guidelines, May 20, 2003

CP 0041, Integrated Planning Process (IPP), July 27, 2001

Other Documents

Condition Assessment of Several Primary Cables for PBNP, May 2003

DBD-01, Auxiliary Feedwater System, March 31, 2000

DBD Validation Procedure, June 2003

DRB Meeting on Tuesday, August 5, 2003 at 11:00PM, 99-036*A, Upgrade U-2 Containment Airlock Operating Mechanism (C-1)

DRB Meeting on Tuesday, August 5, 2003 at 11:00PM, 99-036*A, Upgrade U-2 Containment Airlock Operating Mechanism (C-2)

Engineering CAP Action Backlog Listing

ICAM 1.6, I&C Minimum Staffing, August 16, 2002

IWP 01-128*J-3F, 2SI-856A RHR Pump Suction Isolation MCC Bucket 2B52-323F Replacement, June 19, 2003

List of Design Basis Documents, July 1, 2003

List of Design Changes in Progress DCNs, August 1, 2003

List of Drawing Change Notices, August 1, 2003

List of System Abbreviations

Management Review Meeting Expectations, October 4, 2002

N-97-0154-00-A, Refinements to Electrical AC Power Distribution System Short Circuit Analysis

Outstanding Drawing Changes as of July 28, 2003

Plant Health Committee, FP-E-PHC-01, December 11, 2002

Plant Modification (MR) 01-128*C, Replace 1B-42 Outage Related Breakers (24 Total)

MR 01-128*D, Replace MCC 1B-42 Non-Outage Breaker Buckets to Resolve Bolted Fault Issues

MR 01-128*J, Resolve Bolted Fault Concerns Associated with MCC 2B-32

MR 03-006, Repower AFW Pump Recirculation Valve DPIS Devices from Safety Related Power Supplies, January 22, 2003

Plant Modification Flow Chart

Plant Modification Review Committee, Meeting Agenda

POD Management Update, Bolted Fault Project

Point Beach Organizational Effectiveness Assessment, Conducted December 9, 2002 - January 17, 2003

Program Health Process, August 4, 2003

Q List

System Health Report, May 23, 2003

480 V Breaker Overloads, Protective Relay Setpoints

ACE Training Module

Action Plan for Optimizing the Corrective Action Program at Point Beach, April 7, 2003

Action Plan OP-10-006, Effective Root Cause Evaluations, July 7, 2003

Attendance Record for the ACE Briefing

Attendance Record for the RCE Refresher Training

Charter for the Corrective Action Program Technical Review Panel, May 16, 2003

Charters for all RCE for 2003

Common Factors Assessment, May 28, 2003

CP0026, Change Management Process, September 12, 2001

Current Organizational Chart

Employee Orientation Flow Charts

KPB [Kewaunee/Point Beach] RCE Preparation Checklist

KPB-SA-Corrective Action-2002-01, Kewaunee - Point Beach Assessment of the Corrective Action Program, June 2002

License Renewal Assessment/Engineering Recovery Plan, March 19, 2003

NPM 2002-0240, Minutes from the May 1, 2002 CARB Meeting, May 7, 2002

NPM 2003-0432, Minutes from the June 17, 2003 CARB Meeting, June 18, 2003

NPM 2003-0522, Minutes from the July 22, 2003 CARB Meeting, July 22, 2003

NRC 2003-0065, PBNP Excellence Plan, July 18, 2003

Numbers of CAPs sorted by Significance Level

PBNP Corrective Action Effectiveness Review Job Aid, July 16, 2003

PBNP Corrective Action Program, The Why and How of the Corrective Action Program (CAP)

PBNP Corrective Action Review Board Charter

PBSA-CAP-03-01, Point Beach Corrective Action Program Self-Assessment Report, July 7- 11, 2003

Personnel Who Attended Equipment Root Cause Training from PII (2003)

Point Beach Corrective Action Program Managers Workshop, Course Notes

Point Beach Corrective Action Program Supervisor Review/Approval Guide, June 2003,

Point Beach Corrective Action Review Board Workshop, Course Notes

Point Beach Nuclear Plant 2003-2007 Business Plan

Point Beach Nuclear Plant, 2003 - 2007 Business Plan Briefing Slides

Point Beach Nuclear Plant, 95003 CAP Inspection Entrance Briefing, July 28, 2003

Point Beach Nuclear Plant, Assessment of Potential Vulnerabilities for License Renewal, Martin/Sigmon Consulting Services Inc., March 2003

Qualified RCE Evaluator Roster

RCE Training Module

Request Not to Perform Corrective Actions for Screening Meeting on August 7, 2002 RE: CAP000594

Root Cause Investigation Charter

Root Cause Lead Investigators 2002-2003

SAT Overview Procedure

Schedule for 2003 General CAP Training

CAPs Screening Tool

Design Review Board Charter

Desktop Guide to Assist Supervisors With Review and Closeout of Caps -Excellence Plan 10-004.8

Guideline for Identification and Verification of Issues Related to the Site Excellence Plan, June 12, 2003

Improved Guidance for EOC Assessments

IP 95003, Assessment Guideline, June 12, 2003

IP 95003, Requirements Review Guideline

Method for Trending and Monitoring Equipment - Excellence Plan 10-005.7

PBSA-PBNP-03-01, Point Beach Organizational Effectiveness Assessment, Conducted July 14 - July 18, 2003

Site Excellence Plan Guideline, July 28, 2003

Assessment of Nuclear Engineering Services, Martin/Sigmon Consulting Services Inc., February 1998

FP-E-MOD-07, Design Verification and Technical Review, December 27, 2002

OPR 000070, CAP 034430, Operability Determination Part I, Revision 0

OR 2003-002-3-007, Emergent Assessment, August 5, 2003

OR 2003-002-3-015, Maintenance and Work Control, August 4, 2003

OR 2003-002-3-016, Management Systems, August 5, 2003

OR 2003-002-3-036, Emergent Assessment, August 5, 2003

OR 2003-003-3-022, Training, August 5, 2003

Action Items Older Than 300 days That Remain Open Priority 1, 2, and 3

Documentation of Abbreviations on Modification Lists

Level "A" Apparent Cause Investigation, Inadequate Danger Tagging Clearance for G02 RMP, Completed January 25, 2002

List of Conditions Adverse to Quality CAPS Closed to Work Orders

List of Work Orders That Are Closed Without or Canceled From Priority 4 CAPS or Work Order C or Z

List of Work Orders That Are Closed Without Work

MM Corrective Non-Outage Work List

NMC Trend Code Manual, January 17, 2003

Operating Experience (OE) Improvement Plan

Procedure Periodic Review Backlog

EMERGENCY PREPAREDNESS

<u>Correction of Weaknesses and Deficiencies</u>

SA-Ops-01-06, Gap Analysis, August 2001

Self-Assessment Report, KPB-EP-02-01, April 2002

Self-Assessment Report, KPB EP 02-02, June 18, 2002

Focused Self-Assessment Report KPBNP-EP-02-02, Kewaunee/Point Beach Emergency Preparedness Program Audit of May 28 Through 30, 2002, June 18, 2002

Self-Assessment Report, PBSA-EP-03-01, EP Staffing and Shift Augmentation Requirements, January 31, 2003

Quarterly Effectiveness Review Report, Emergency Preparedness, 1st and 2nd Quarters 2003

PBNP NRC EP Readiness Assessment, January 30, 2003

ERO Training Program Description, August 2003

RCE000187, Failure of the EP Critique Process To Identify Drill/Exercise Weaknesses, Revisions 0, 1, and 2

RCE000194, RCE000187 Did Not Meet Standards to Close NRC Inspection, Revisions 0 and 1

ACE000662, Wellhouse Propane Tank Leak, March 6, 2002

ACE001112, March 4, 2002 - UE Declaration May Not Be a Timely Declaration (CAP030381), December 13, 2002

OTH028187, Four Measures to Improve RCE Quality, February 18, 2003

OTH029034, Compare Timeline of March 4, 2003 Event With NEI 99-02 for PI Requirements, April 8, 2003

OTH029037, Review Documentation of March 4, 2003 Event For Inconsistencies Between Reports, CAPs, Control Room Logs and Other Reports, April 8, 2003

NPM 2002-0116, Report of Unusual Event, March 4, 2002

NPM 2002-0158, Emergency Preparedness Response to March 4, 2002 Unusual Event, March 27, 2002

NPM 2002-0612, Minutes From the November 15, 2002 Corrective Action Review Board (CARB) Meeting, November 18, 2002

NP 5.3.2, Industry Operating Experience Review Program, Revision 12

CAP002385, March 4, 2002 Wellhouse Propane Tank Leak and Unusual Event, March 4, 2002

CAP028396, EP Documentation of 2001 Annual EAL Review With State/Counties Not Available, June 5, 2002

CAP030381, March 4, 2002 Unusual Event Declaration May Not Be A Timely Declaration, December 11, 2002

CAP031099, 2002 EAL Review With State and Counties Not Formally Documented With Signatures, February 12, 2003

CAP031548, Focused Self-Assessment KPBNP-EP-02-02 Not Distributed in a Timely Manner - Date Completed in Question, March 10, 2003

CAP032422, A Formal Method For Scheduling Ingestion Exercises With the State Is Needed, April 28, 2003

Effectiveness Review (EFR)028122, Excellence Plan CA2, Ensure That Multi-Discipline Teams Perform Team Investigations, February 18, 2003

EFR028123, Excellence Plan CA3, Ensure Adequate Number of RCE-Qualified Personnel Are at Point Beach, February 18, 2003

CA027674, Revise the Report of the March 4, 2002, Propane Tank Leak Unusual Event Documented in NPM 2002-0158, January 14, 2003

CA027675, Annotate the Station Log Entries for the March 4, 2002, Unusual Event Declaration, January 14, 2003

CA028117, Direct the Performance of a RCE for Any NRC Finding That is Worse Than Green, February 18, 2003

CA028118, Increase the Number of RCE-Qualified Personnel, February 18, 2003

CA028119, Develop a Minimum Set of Requirements or Qualifications to Function as a RCE Team Leader, February 18, 2003

CA028120, Develop a Standard Review/Grading Checklist for CARB Use When Reviewing Completed RCE, February 18, 2003

CA028121, Develop a Management Expectation for the RCE Management Sponsor to Provide RCE Status Updates to the CARB, February 18, 2003

CA028285, Strengthen the Roles and Responsibilities of the Management Sponsor of a RCE, February 26, 2003

CA028286, Establish a RCE Mentor Position to Aid RCE Investigators, February 26, 2003

CE011554, A Formal Method For Scheduling Ingestion Pathway Exercises With the State Is Needed, April 28, 2003

NEI 99-02, Regulatory Assessment Performance Indicator Guideline, Revision 2, November 2001

<u>ERO Readiness</u>

CAP034650, Potential Enhancement Needed For ERO Participation PI Key Position Tracking, August 7, 2003

CAP034652, Inadequate Communication of UE Evaluation Results in Inaccurate Declaration, August 7, 2003

CAP034693, Evaluate the Availability of Seismic Monitor Data Computers and Seismic Monitors, August 8, 2003

1984 E-Plan and Safety Evaluation Report

NP 4.2.28, Health Physics Represented Personnel Assignment and Scheduling Policy, August 18, 2001

<u>Facilities and Equipment</u>

NUREG 0696, Functional Criteria for Emergency Response Facilities, February 1981

FEMA-Approved Alert and Notification System Design Report, 1982

Plant Health Committee Meeting Minutes, May 9, 2003, and August 1, 2003

White Paper on Configuration Management, 2003

Letter to NRC Region III Regional Administrator from Assistant Vice President, Emergency Preparedness Confirmation of Action, Point Beach Nuclear Plant, Units 1 and 2, February 18, 1982

Emergency Plan Chapter 7, Emergency Facilities and Equipment, Revisions 45 and 46

Instructions for Modular Meteorological System with Telemetry, Climatronics Job Number 7381, May 13, 1982

Vendor Inspection Report on Condition of Meteorological Towers, June 26, 2000

Emergency Plan Maintenance Procedure (EPMP) 5.0, Post-TMI Meteorological Monitoring Program Design, Operation, and Maintenance, Revisions 4, 5, and 7

Instrument and Control Procedure (ICP) 6.55, Meteorological Instrumentation Calibration, Revisions 5, 6, 7, 8, and 9

Sample of ICP 6.55 Calibration Records, November 1994, June 1999, July 2000, July 2001, July 2002, and May 2003

10 CFR 50.59 Screening Record 2003-0184, Meteorological Instrumentation Calibration Procedure ICP 6.55, May 2, 2003

ICP 7.30, Meteorological Monitoring System (Bi-monthly Surveillance Checklist), Revision 4

Excerpts of Control Room Log Entries on Placing Onsite and Inland Meteorological Monitoring Systems Out of Service Due to Being Out of Calibration, May 2, 2003

Excerpts of Control Room Log Entries on Placing Certain Onsite Meteorological Monitoring System Components Back in Service Following Re-calibration, May 3, 2003

CAP030676, Loss of Direct Current Power to the SBCC's Emergency Notification System Telephone, January 10, 2003

CAP032129, Proceduralized Backup Sources for Wind Speed Indications, April 9, 2003

CAP032232, Assess Use of the SBCC Data Center's Propane-Powered Generator as Backup Power Supply for EOF Equipment, April 14, 2003

CAP032569, Primary Tower's 45 Meter Wind Direction Indicator is Occasionally Inaccurate, April 30, 2003

CAP032593, Meteorological Measurement Tolerances Are Not in Accordance With NRC Commitments, May 1, 2003

CAP032877, Meteorological System Alarm Setpoints Not Properly Configured on Plant Process Computer System, May 14, 2003

CAP034511, Adequacy of Work Control for Phone Systems at the SBCC, August 1, 2003

CA029777, Create Instructions to Follow When Equipment Referenced in EALs Is Out of Service, May 14, 2003

Assessment of the Point Beach Meteorological Equipment Following the Ice Storm of April 3 and 4, 2003, August 4, 2003

2003 White Paper on Configuration Management of the EOF in the Site Boundary Control Center (SBCC), undated

Plant Health Committee Meeting Minutes on SBCC/EOF Modifications Control, August 1, 2003

OTH029216, Assessment of SBCC Data Center's Propane-Powered Generator as a Backup Power Supply for EOF Equipment, July 24, 2003

WO 0203763-001, Inspect and Maintain SBCC's Air Conditioning System

WO 0203774, Inspection and Maintain SBCC's Air Filtration System

In-Place Test Reports for TSC's Air Filtration and Adsorber Bed Systems, June 11, 2003

NP 4.2.28, Health Physics Represented Personnel Assignment and Scheduling Policy, April 18, 2001

Procedure Quality

CA029777, Create a Procedure to Follow When EP-Related Equipment Is OOS, May 14, 2003

CAP030938, FT-3299B, DAVS Isokinetic Sampler Flow Channel Failed High, January 30, 2003

CAP032427, U2 Condenser Air Removal Oscillations Affect On Primary to Secondary Leak Detection, April 24, 2003

PBNP Excellence Plan, July 11, 2003

NP 1.8.3, 10 CFR 50.54(q) Evaluations, Revision 1

ERO Performance

July 31, 2003, Off-hours Emergency Facility Activation Drill Results

August 14, 2003 Emergency Preparedness Exercise Scenario, Notification Forms, Facility Logs, Dose Assessment Evaluations, and Final Drill Critique

EPMP 3.2, Offsite Personnel and Emergency Preparedness Staff Training, Revisions 10 and 11

July 28 and Aug 4, 2003 Licensed Operator Requalification Drills

CA026651, Revise EPIP 11.2 and EPMP 1.3e to Reflect Changes Made to Medical Kits in Control Room, October 9, 2002

CA027769, CATPR #3: Develop Program to Address Training and Development Needs of EP Staff, January 22, 2003

CA032011, CATPR #3 of RCE000187 Closed With Incomplete Actions - Review CAP033979 and Implement Recommendations, July 14, 2003

CAP028952, August 1 Drill EAL for Site Emergency, August 5, 2002

CAP029232, Reassess Number of Medical Emergency First Responder Kits in Control Room, September 6, 2002

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LIST OF ACRONYMS USED

AC	Alternating Current
ACE	Apparent Cause Evaluation
AFW	Auxiliary Feedwater
amp	Ampere
ANS	Alert and Notification System
AOP	Abnormal Operating Procedure
AOV	Air-Operated Valve
ATC	American Transmission Company
AV	Apparent Violation
CA	Corrective Action
CAP	Corrective Action Program Problem Identification Document
CATPR	Corrective Action to Prevent Recurrence
CARB	Corrective Action Review Board
CC	Component Cooling (Water)
CCW	Component Cooling Water
ΔCDF	Change in Core Damage Frequency
CE	Condition Evaluation
CLB	Current Licensing Basis
CR	Condition Report (the former Corrective Action Program Problem Identification Document)
CSP	Critical Safety Procedure
CST	Condensate Storage Tank
DBD	Design Basis Document
DC	Direct Current
DEP	Drill and Exercise Performance
DRB	Design Review Board
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
EAL	Emergency Action Level
ECA	Emergency Contingency Action
ECP	Employee Concerns Program
EDG	Emergency Diesel Generator
EFR	Effectiveness Review
ENS	Emergency Notification System
EOF	Emergency Operations Facility
EOP	Emergency Operating Procedure
EOPSTPT	EOP Setpoint Basis Document
EP	Emergency Preparedness/Emergency Planning
EPAC	Emergency Preparedness Advisory Committee
EPIP	Emergency Plan Implementing Procedure
EPMP	Emergency Plan Maintenance Procedure
EPZ	Emergency Planning Zone
EQ	Environmental Qualification
ERO	Emergency Response Organization
FEMA	Federal Emergency Management Agency
FME	Foreign Material Exclusion

FSAR	Final Safety Analysis Report
GE	General Emergency
GL	NRC Generic Letter
gpm	Gallons Per Minute
HELB	High-Energy Line Break
HEP	Human Error Probability
HVAC	Heating, Ventilation, and Air Conditioning
HX	Heat Exchanger
IA	Instrument Air
I&C	Instrument and Control
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Inspection Report
ISI	Inservice Inspection
IST	Inservice Testing
IT	Inservice Test
JPIC	Joint Public Information Center
kV	Kilovolt(s)
kVA	Kilovolt-ampere
LER	Licensee Event Report
LCO	Limiting Condition for Operation
LOCA	Loss-of-Coolant Accident
LLOCA	Large-Break Loss-of-Coolant Accident
LOA	Letter of Agreement
LOIA	Loss of Instrument Air
LOOP	Loss of Offsite Power
LOR	Licensed Operator Requalification
MC	Manual Chapter
MDAFW	Motor-Driven Auxiliary Feedwater
MOV	Motor-Operated Valve
MR	Plant Modification
MRE	Maintenance Rule Evaluation
NEI	Nuclear Energy Institute
NMC	Nuclear Management Company, LLC
NOS	Nuclear Oversight (Quality Assurance)
NOUE	Notification of Unusual Event
NP	Nuclear Plant Business Unit Procedure
NPM	Point Beach Memorandum
NRC	Nuclear Regulatory Commission
OD	Operability Determination
ODI	Old Design Issue
OE	Operating Experience
OI	Operating Instructions
OM	Operations Manual
OP	Operating Procedure
OPR	Operability Request
OTH	Other (corrective action program document)
PAB	Primary Auxiliary Building
PAR	Protective Action Recommendation

PARS	Publicly Available Records System
PBNP	Point Beach Nuclear Plant
PCP	Power Conversion Products
PI	Performance Indicator
P&ID	Piping and Instrumentation Diagram
PRA	Probabilistic Risk Assessment
psig	Pounds Per Square Inch - Gauge
QRT	Quality Review Team
RCE	Root Cause Evaluation
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RSPS	Risk Significant Planning Standard
SAE	Site Area Emergency
SBCC	Site Boundary Control Center
SDP	Significance Determination Process
SER	Safety Evaluation Report
SEM	Scanning Electron Microscopy
SEN	Significant Event Notice
SGTR	Steam Generator Tube Rupture
SPEED	Spare Parts Equivalency Evaluation Document
SR	Surveillance Requirement
SS	Safety Screening
SSFA	Safety System Functional Assessment
SW	Service Water
TDAFW	Turbine-Driven Auxiliary Feedwater
TPCS	Transients Without Power Conversion System
TRANS	Transients
TS	Technical Specification
TSC	Technical Support Center
UAT	Unit Auxiliary Transformer
URI	Unresolved Item
V	Volt(s)
Vac	Volt(s) Alternating Current
VDC	Volt(s) Direct Current
VIO	Violation