August 12, 2004

Mr. Dennis L. Koehl
Site Vice-President
Point Beach Nuclear Plant
Nuclear Management Company, LLC
6590 Nuclear Road
Two Rivers, WI 54241-9516

SUBJECT: POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2
NRC INTEGRATED INSPECTION REPORT 05000266/2004003;
05000301/2004003

Dear Mr. Koehl:

On June 30, 2004, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Point Beach Nuclear Plant, Units 1 and 2. The enclosed report documents the inspection findings which were discussed on July 16, 2004, with you and members of your staff.

The inspection examined 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. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

Based on the results of this inspection, one self-revealed finding and five NRC-identified findings of very low safety significance were identified, five of which involved a violation of NRC requirements. However, because the violations were of very low safety significance and because the issues were entered into the licensee's corrective action program, the NRC is treating these violations as Non-Cited Violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. Additionally, a licensee-identified violation determined to be of very low safety significance is listed in this report.

Two of the findings involved the installation of steam generator nozzle dams during the Unit 1 refueling outage while the reactor coolant system was at a reduced inventory level. The performance issues associated with these findings could have resulted in nuclear and industrial safety consequences of higher significance.

In addition to the routine NRC inspection and assessment activities, Point Beach performance is being evaluated quarterly as described in the Annual Assessment Letter - Point Beach Nuclear Plant, dated March 4, 2004. Consistent with Inspection Manual Chapter (IMC) 0305, "Operating Reactor Assessment Program," 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. On April 30, May 24, and June 16, 2004, the NRC reviewed Point Beach operational performance, inspection findings, and performance indicators for the second quarter of 2004. Based on this review, we concluded that Point Beach is operating safely. We determined that no additional regulatory actions, beyond the already increased inspection activities and management oversight, are currently warranted.

If you contest the subject or severity of an NCV in this report, 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, 2443 Warrenville Road, Suite 210, Lisle, IL 60532 - 4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the Resident Inspector Office at the Point Beach Nuclear Plant facility.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and any response you provide will be 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/

Steven A. Reynolds, Acting Director
Division of Reactor Projects

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

Enclosure: Inspection Report 05000266/2004003; 05000301/2004003
w/Attachment: Supplemental Information

See Attached Distribution

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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:	05000266/2004003; 05000301/2004003
Licensee:	Nuclear Management Company, LLC
Facility:	Point Beach Nuclear Plant, Units 1 and 2
Location:	6610 Nuclear Road Two Rivers, WI 54241
Dates:	April 1 through June 30, 2004
Inspectors:	P. Krohn, Senior Resident Inspector M. Morris, Resident Inspector D. Karjala, Resident Inspector P. Higgins, Resident Inspector S. Ray, Senior Resident Inspector M. Kunowski, Project Engineer R. Alexander, Radiation Specialist B. Jorgensen, NRC Consultant M. Holmberg, Reactor Inspector D. Schrum, Reactor Engineer T. Ploski, Senior Emergency Preparedness Inspector C. Zoia, Operator Licensing Examiner
Approved by:	P. Louden, Chief Branch 7 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

IR 05000266/2004003, 05000301/2004003; 04/01/2004 - 06/30/2004; Point Beach Nuclear Plant, Units 1 & 2; Fire Protection, Inservice Inspection Activities, Access Control to Radiologically Significant Areas, Identification and Resolution of Problems, Event Follow-up, and Temporary Instruction (TI) 2515/153, "Reactor Containment Sump Blockage."

This report covers a three-month period of baseline resident inspection and announced inservice inspection (Inspection Procedure (IP) 71111.08), heat sink (IP 71111.07B), and radiation protection (IP 71121) baseline inspections for Point Beach Nuclear Plant, Units 1 and 2. In addition, TI inspections were completed in the areas of reactor pressure vessel head and vessel head penetration nozzles (TI 2515/150, Unit 1), reactor pressure vessel lower head penetration nozzles (TI 2515/152, Unit 1), reactor containment sump blockage (TI 2515/153, Units 1 and 2), spent fuel material control and accounting (TI 2515/154, Units 1 and 2), and offsite power system operational readiness (TI 2515/156, Units 1 and 2). The inspections were conducted by 12 inspectors: a radiation specialist inspector, an inservice inspection specialist inspector, a heat sink specialist inspector, a senior emergency preparedness inspector, a project engineer, an NRC consultant inspector, an operator licensing examiner, and five resident inspectors. One Green finding that was not a violation of NRC requirements and five Green findings that were Non-Cited Violations (NCVs) 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. Inspector-Identified and Self-Revealed Findings

Cornerstone: Initiating Events

- Green. The inspectors identified an NCV of 10 CFR 50.48(a)(2)(i) having very low safety significance when transient combustibles were stored in the Unit 1 containment building and the turbine building without required administrative controls. The finding also affected the cross-cutting area of human performance in that the licensee failed to identify the transient combustible materials during tours required by the Fire Protection Evaluation Report.

  The inspectors concluded that the finding is more than minor because it affected the Reactor Safety Initiating Events Cornerstone objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown, specifically protection against external factors (fire). The inspectors determined that the finding was of very low safety significance (Green), since the issue was assigned a low degradation rating and the quantity of transient combustibles had been bounded by the analysis contained in the Fire Hazards Analysis Report. The licensee has entered this finding into its corrective action (CA) program. (Section 1R05.1)

- Green. The inspectors identified a finding associated with installing steam generator nozzle dams and establishing a hot leg vent path during a portion of the Unit 1 cycle 28 refueling outage (U1R28). The primary cause of this finding was related to the cross-cutting area of human performance, involving the decision by several licensed and experienced personnel to allow nozzle dam installation to commence prior to establishment of a vent path through the pressurizer manway.

  The finding is considered more than minor because it affected: (1) the Reactor Safety Initiating Events Cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown operations, and (2) the human performance attribute of the Initiating Events Cornerstone. The finding was considered to be of very low safety significance and did not require quantitative assessment since: (1) conditions meeting a loss of control were not met in that no inadvertent change in reactor coolant system temperature or change in reactor vessel level actually occurred, and (2) the licensee had maintained adequate mitigation capability for the existing plant conditions. No violation of regulatory requirements occurred because: (1) the actual sequence of events showed that all four nozzle dams had not been completely installed while the pressurizer manway was still in place, and (2) an engineering analysis showed that an adequate hot leg vent path was available while one of the 'A' steam generator hot leg nozzle dam side pieces was not installed. The licensee has entered this finding into its corrective action (CA) program. (Section 4OA2.5)

Cornerstone: Mitigating Systems

- Green. The inspectors identified an NCV of 10 CFR 50.55a(a)(3)(i) for the licensee's incorrect substitution of weld surface examinations into the risk-based portion of the Inservice Inspection Program, which required volumetric weld examinations.

  This finding is greater than minor because it affected the Mitigating Systems Cornerstone objective of equipment reliability and, if left uncorrected, could allow unacceptable piping system weld flaws to remain in-service and render safety-related systems inoperable. The finding is of very low safety significance because the licensee had sufficient time left in the Code interval to perform the required number of volumetric examinations of piping welds in the affected risk-based category during future Unit 1 outages. The licensee has entered this finding into its corrective action (CA) program. (Section 1R08)

- Green. An NCV of Technical Specification (TS) Surveillance Requirement (SR) 3.5.1.2 was self-revealed when the water volume in the Unit 2 safety injection (SI) accumulator, 2T-34A, exceeded the TS limit of 1136 cubic feet.

  The finding is greater than minor because it affected the Reactor Safety Mitigating Systems Cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events. The finding was considered to be of very low safety significance since: (1) the Nuclear Steam Supply System vendor performed an analysis of the over-filled, as-found condition and determined that the 2T-34A accumulator had been capable of performing the design basis function and would not have challenged the 10 CFR 50.46 Loss-of-Coolant-Accident acceptance criteria, and (2) the finding did not result in a design or qualification deficiency, an actual loss of safety function, or involve internal or external initiating events. The licensee has entered this finding into its corrective action (CA) program. (Section 4OA3.1)

- Green. The inspectors identified an NCV of 10 CFR Part 50, Appendix B, Criterion VI, "Document Control," having very low safety significance associated with Unit 1 emergency operating procedures when a software error deleted reference to two of five indications intended to monitor primary containment sump performance during the recirculation phase of a design basis accident. Specifically, the RHR Pump Operation - NORMAL and SI Pump Operation - NORMAL substeps of Unit 1 emergency operating procedure EOP-1, "Loss of Reactor or Secondary Coolant," Step 29c, Revision 35, were deleted by the software program and not detected by operations personnel for a period of approximately 9 months. The primary cause of this finding was related to the cross-cutting area of human performance in that despite previous knowledge of the software problem and operations department management expectations to perform line-by-line reviews prior to distribution, 16 errors occurred in safety-related emergency operating, emergency contingency action, critical safety, and shutdown emergency procedures for Units 1 and 2.

  The inspectors determined that the finding is more than minor because it affected the procedure quality attribute of the Mitigating Systems Cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events. The finding was considered to be of very low safety significance because it did not result in a design or qualification deficiency, an actual loss of safety function, or involve internal or external initiating events. The licensee has entered this finding into its corrective action (CA) program. (Section 4OA5.4.b.2)

Cornerstone: Occupational Radiation Safety (OS)

- Green. A finding of very low safety significance and an associated NCV were identified through an NRC-identified event, when on April 9, 2004, while installing steam generator nozzle dams, licensee staff increased supplied breathing air pressure in excess of procedural requirements while attempting to mitigate lost or diminished air flow to contract workers who were utilizing continuous flow, supplied-air respirator "bubble hoods." The inspectors determined that the licensee failed to meet the requirements of 10 CFR 20.1703, when the licensee increased the air line pressure in excess of the procedural guidance, which resulted in the licensee utilizing a respiratory protection device contrary to its National Institute for Occupational Safety and Health (NIOSH) certification.

  The inspectors determined that the finding is more than minor because use of a respiratory protection device outside its specifications could impact internal dose, and if left uncorrected, could become a more significant safety concern. The finding was considered to be of very low safety significance because no internal exposure to radioactive material resulted from the use of the bubble hoods with higher air line pressure than allowed. The licensee has entered this finding into its corrective action (CA) program. (Section 2OS1.2.b)

B. Licensee-Identified Violations

A violation of very low 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. This violation and corrective action tracking number are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period in coastdown at 92 percent power prior to the Unit 1 cycle 28 refueling outage (U1R28), which began on April 2, 2004. Unit 1 achieved criticality on June 7, after completion of the outage, and returned to full power on June 11. Power was reduced to 55 percent later the same day to address high vibrations associated with the 1P-28B main feedwater pump. Following maintenance on the pump, Unit 1 returned to full power on June 14 and remained there through the end of the inspection period.

Unit 2 began the inspection period at full power and remained there until May 15, 2004, when the Unit was manually tripped after communications were lost with a diver performing inspections at the circulating water (CW) intake crib. Unit 2 returned to full power on May 20. Unit 2 remained at or near full power for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, and Emergency Preparedness

1R01 Adverse Weather Protection (71111.01)

.1 High Wind/Tornado Preparations

a. Inspection Scope

During the week of April 20, 2004, the inspectors reviewed the facility design and licensee procedures to evaluate the plant's likely response to high winds and tornadoes. Additionally, the inspectors walked down selected areas to evaluate plant buildings, switchyard, and equipment susceptible to high winds and tornadoes. The inspectors also reviewed Abnormal Operating Procedure (AOP), AOP-13C, "Severe Weather Conditions," dated June 30, 2003, which prescribed station actions for severe weather conditions and several corrective action program documents (CAPs) associated with recent high wind conditions. This inspection activity constituted one inspection sample.

b. Findings

No findings of significance were identified.

.2 Hot Weather Preparations

a. Inspection Scope

During the week of June 14, 2004, the inspectors reviewed the facility design and licensee procedures to evaluate preparations for summertime high temperatures. Additionally, the inspectors walked down selected areas to evaluate plant equipment susceptible to high temperatures. The inspectors evaluated changes to the methodology used to perform hot weather preparations and compared the changes to those made as a result of the lessons learned during cold weather preparations. This inspection activity constituted one inspection sample.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

.1 Partial System Walkdowns

c. Inspection Scope

The inspectors performed three partial walkdowns of accessible portions of risk-significant systems to evaluate the operability of the selected systems. The inspectors utilized valve and electrical breaker checklists (CLs), tank level books, plant drawings, and selected operating procedures to determine if the components were properly positioned and supported the systems as needed. The inspectors also examined the material condition of the components and observed operating equipment parameters to check for obvious deficiencies. The inspectors reviewed completed work orders (WOs) and calibration records associated with the systems for issues that could affect component or train function. The inspectors used the information in the appropriate sections of the Final Safety Analysis Report (FSAR) to determine the functional requirements of the system. These observations constituted three quarterly inspection samples.

The inspectors verified the alignment of the following systems:

- Residual Heat Removal (RHR), Train 'A' on April 8, 2004;
- RHR, Train 'B' on May 12, 2004; and
- Spent Fuel Pool (SFP) Cooling, on May 13, 2004.

b. Findings

No findings of significance were identified.

.2 Complete System Walkdown

c. Inspection Scope

On May 18, 2004, the inspectors performed a complete system alignment inspection of 345-Kilo-Volt (KV) and 13.8-KV systems. These systems were selected because they were considered both safety-significant and risk-significant in the licensee's probabilistic risk assessment. The inspection consisted of the following activities:

- a review of plant procedures (including selected abnormal and emergency procedures), drawings, and the FSAR to identify proper system alignment;

- a review of outstanding or completed temporary and permanent modifications to the systems;
- a review of open CAPs and WOs that could impact operability of the systems; and
- a walkdown of mechanical and electrical components in the systems to verify proper alignment, component accessibility, availability, and current condition.

The inspectors also reviewed selected issues to determine if they had been properly addressed in the licensee's corrective action (CA) program. This inspection activity constituted one inspection sample.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Walkdown of Selected Fire Zones

a. Inspection Scope

The inspectors conducted walkdowns focused on availability, accessibility, and the condition of fire fighting equipment, the control of transient combustibles and ignition sources, and on the condition and operating status of installed fire barriers. The inspectors selected nine fire areas for inspection based on the area's overall fire risk contribution, as documented in the licensee's Individual Plant Examination of External Events, the area's potential to impact equipment which could initiate a plant transient, or the area's impact on the plant's ability to respond to a security event. The inspectors used the documents listed in the attachment to this report to determine if fire hoses and extinguishers were in their designated locations and available for immediate use, fire detectors and sprinklers were unobstructed, transient material loading was within the analyzed limits, and fire doors, dampers, and penetration seals were in satisfactory condition. These observations constituted nine quarterly inspection samples.

The following areas were inspected by walkdowns:

- Fire Zone 505, Unit 1 Containment, 8 foot;
- Fire Zone 511, Unit 1 Containment, 21 foot;
- Fire Zone 516, Unit 1 Containment, 48 foot;
- Fire Zone 520, Unit 1 Containment, 66 foot;
- Fire Zone A23N, Auxiliary Feedwater (AFW) Pump Room (North);
- Fire Zone A23S, AFW Pump Room (South);
- Fire Zone 142, Component Cooling Water (CCW) Pump Room;
- Fire Zone 156, Motor Control Center Room - 1B32; and
- Fire Zone 166, Motor Control Center Room - 2B32

b. Findings

Introduction: The inspectors identified an NCV of 10 CFR 50.48(a)(2)(i) having very low safety significance (Green) for transient combustibles stored in the Unit 1 containment building and the turbine building without required administrative controls.

Description: Inspectors identified that significant quantities of transient combustible materials were stored in the Unit 1 containment and the turbine buildings during U1R28 without required administrative controls. The materials in the containment building included 11 drums of lubricating oil and storage shelves of radiation protection materials (cloth and plastic contamination control clothing and supplies). The inspectors also identified 8 drums of waste oil in the turbine building adjacent to AFW pump and emergency diesel generator (EDG) rooms. Permits did not exist for the storage of these materials as required by the Fire Protection Evaluation Report (FPER), Section 3.1.2.2, “Transient Combustible Control,” and Section 7.3.1, “Containment.”

Analysis: The inspectors determined that failing to implement administrative controls for transient combustible materials in areas containing, and adjacent to, safety-related equipment was a performance deficiency warranting a significance evaluation. The inspectors concluded that the finding was more than minor in accordance with Inspection Manual Chapter (IMC) 0612, “Power Reactor Inspection Reports,” Appendix B, “Issue Disposition Screening,” issued on January 14, 2004. The finding affected the Reactor Safety Initiating Events Cornerstone objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown, specifically protection against external factors (fire). The finding also affected the cross-cutting area of human performance in that personnel failure to identify transient combustible materials during tours required by FPER, Section 3.1.2.2, “Transient Combustible Control,” and Section 7.3.1, “Containment.”

The inspectors completed a significance determination of this issue using IMC 0609, “Significance Determination Process (SDP),” dated March 21, 2003, and Appendix F, “Fire Protection SDP,” issued May 28, 2004. The inspectors determined that the finding was of very low safety significance (Green), since the issue was assigned a low degradation rating and the quantity of transient combustibles had been bounded by the analysis contained in the Fire Hazards Analysis Report (FHAR). This finding was assigned to the Reactor Safety Initiating Events Cornerstone for Unit 1.

Enforcement: 10 CFR 50.48(a)(2)(i) requires that the fire protection plan include administrative controls for fire prevention. The FPER, Section 3.1.2.2, “Transient Combustible Control,” and Section 7.3.1, “Containment,” require that administrative controls be maintained for use of transient combustible material. Contrary to these requirements, significant quantities of transient combustible materials were found in areas of the Unit 1 containment and turbine buildings without the required administrative controls. Because this violation was of very low safety significance and it was entered into the licensee’s CA program, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy. (NCV 05000266/2004003-01).

1R07 Heat Sink Performance (71111.07)

.1 Resident Inspector Annual Review of Heat Sink Performance

a. Inspection Scope

The inspectors evaluated the performance of the containment air cooler heat exchangers (HXs) by conducting a review of licensee programs and practices that assess HX performance on an ongoing basis and maintain that performance at acceptable levels. The inspectors also determined if potential HX vulnerabilities and deficiencies were identified and were being addressed in the CA program. Finally, the inspectors reviewed HX testing and performance data to evaluate the condition of the containment air cooler HXs. This inspection activity constituted one inspection sample.

b. Findings

No findings of significance were identified.

.2 Biennial Review of Heat Sink Performance

a. Inspection Scope

The inspectors reviewed documents associated with inspection, cleaning, and performance trending of HXs primarily focusing on the CCW HX, HX-12C, and the coolant HXs for EDGs G01 and G02. These HXs were chosen based upon their importance in supporting required safety functions, as well as relatively high risk achievement worth in the plant specific risk assessment. The component cooling HX was also selected to evaluate the licensee's thermal performance testing methods. During the inspection, the inspectors reviewed calculations to determine if these activities adequately ensured proper heat transfer. The inspectors reviewed the documentation to confirm that the inspection methodology was consistent with accepted industry and scientific practices, based on review of heat transfer texts and Electrical Power Research Institute (EPRI) standards. Specifically, the inspectors reviewed the licensee's heat transfer related calculations and/or maintenance activities to confirm that the minimum design heat transfer capability was maintained for these HXs, in accordance with licensee commitments to Generic Letter (GL) 89-13, "Service Water System Problems Affecting Safety-Related Equipment," and limiting design performance values identified in the FSAR.

The inspectors performed a field walkdown of the CCW HXs, the service water (SW) chemical treatment system, and the copper ion generator system. In addition, the inspectors observed the cleaning of the G01 coolant HX.

The inspectors' review of licensee activities and documents regarding the component cooling HX and EDG coolant HXs constituted three samples (two required) for the biennial review of heat sink performance in accordance with Section 71111.07-05 of Inspection Procedure (IP) 71111.07, "Heat Sink Performance."

The inspectors reviewed documents associated with licensee controls for the SW from the ultimate heat sink (UHS) to prevent clogging due to macrofouling and biotic fouling. These two attributes met the procedure requirements for verifying the performance of the UHS.

The inspectors reviewed CAs concerning HX and UHS performance issues to determine if the licensee had an appropriate threshold for identifying issues and entering them in the CA program. The inspectors also evaluated the effectiveness of the CAs for identified issues, including the engineering justification for operability.

The documents that were reviewed are included at the end of this report.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (IP 71111.08)

a. Inspection Scope

For Unit 1, the inspectors evaluated the implementation of the licensee's inservice inspection (ISI) program for monitoring degradation of the reactor coolant system boundary and risk significant piping system boundaries, based on a review of nondestructive examination (NDE) records.

From April 5 through 28, 2004, inside the Unit 1 containment building, the inspectors observed ultrasonic (UT) examinations, which constituted one type (volumetric) of NDE activity. Specifically, the inspectors observed UT examination of two pressurizer spray line welds (RC-03-PS-1001-14 and 15), two auxiliary feedwater system welds (AF-03-1002-76 and 77), and one feedwater system weld (FW-16-FW-1002-15). Additionally, the inspectors observed a second and third type of NDE activity related to the under head vent line dye penetrant (PT) examination of reactor vessel nozzle No. 26 J-groove weld and a visual (VT-3) examination of a feedwater system hanger (EB-9-FW-1111). The inspectors selected these components in order of risk priority as identified in Section 71111.08-03 of IP 71111.08, "Inservice Inspection Activities." The inspectors evaluated these examinations for compliance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Section XI and plant Technical Specification (TS) requirements and to determine if indications and defects (if present) were dispositioned in accordance with the ASME Code. This review counted as two inspection samples as described in Section 71111.08-5 of IP 71111.08.

From April 5 through 28, 2004, in an office on the 8-foot level of the Technical Support Building (TSB), the inspectors reviewed the licensee's records related to three examinations (summary report 004500 for control rod drive housings No. 1, reactor pressure vessel head flange report 99U1-350P004, and reactor pressure vessel Stud No. 44 report 99U-350P021) with recordable indication accepted for continued service. The inspectors evaluated these examinations for compliance with ASME Code Section XI. This review counted as one inspection sample as described in Section 71111.08-5 of IP 71111.08.

From April 5 through 28, 2004, in an office on the 8-foot level of the TSB, the inspectors reviewed the licensee's records related to pressure boundary welding to replace pipe and elbows on 2-inch lines to the T-34B safety injection system accumulator (Class 2 component). Specifically, the inspectors reviewed records for welds FW-1 and FW-2 to determine if the welding acceptance and preservice examinations (e.g., pressure testing, visual, dye penetrant, and weld procedure qualification tensile tests and bend tests) were performed in accordance with ASME Code, Section III, Section V, Section IX, and Section XI. This review counted as one inspection sample as described in Section 71111.08-5 of IP 71111.08.

From April 5 through 28, 2004, in an office on the 8-foot level of the TSB, the inspectors reviewed the licensee's records associated with two ASME Code Section XI replacement activities (replace pipe and elbows on 2-inch lines to the T-34B safety injection system accumulator) for Code Class 2, to verify that the ASME Code Section III, Section V, and Section XI requirements were met. This review counted as one inspection sample as described in Section 71111.08-5 of Inspection Procedure 71111.08.

From April 5 through May 14, 2004, in Room 138 of the on-site training building, the inspectors observed acquisition of steam generator (SG) tube eddy current (ET) data for the Unit 1 SGs. The inspectors also reviewed the SG ET examination scope, expansion criteria, analysis procedures, and examination reports for the Unit 1 'A' and 'B' SGs to confirm that:

- TS requirements were met;
- the inspection was consistent with the EPRI Guidelines;
- areas of potential degradation were inspected; and
- ET probes and equipment were qualified in accordance with the EPRI Guidelines for the expected types of tube degradation.

The inspectors concluded that the review discussed above did not count as a completed inspection sample as described in Section 71111.08-5 of IP 71111.08, but the sample was completed to the extent possible. The specific activities that were not available for review to complete this inspection sample are identified in the table below.

Inspection Procedure 7111108 Section Number	Reason Activity was Unavailable For Inspection	Reduction in Inspection Procedure Samples
Section 02.02.a 1 thru 4: associated with review of licensee in-situ pressure testing of steam generator tubes.	The licensee did not identify any tubes that required pressure testing.	The inspectors concluded that these unavailable activities constituted a reduction by one from the total number of procedure samples required by Section 71111.08-5 of Inspection Procedure 71111.08.

Inspection Procedure 7111108 Section Number	Reason Activity was Unavailable For Inspection	Reduction in Inspection Procedure Samples
Section 02.02.f and g: confirm that all repair processes used were approved in the technical specifications for use at the site; reviewed tube repair criteria.	The licensee did not identify any tubes that required repair.	
Section 02.02.h: associated with steam generator tube leakage greater than 3 gallons per day.	The licensee reported that no steam generator tube leakage had been observed.	
Section 02.02.k: associated with review of one to five samples of eddy current data.	The inspectors did not identify any "serious questions" regarding the eddy current data.	

The specific list of documents reviewed by the inspectors in conducting this inspection are listed in the attachment to this report.

b. Findings

b.1 Substitution of Weld Surface Examinations for Volumetric Examinations

Introduction: The inspectors identified a Green NCV of 10 CFR 50.55a(a)(3)(i) for the licensee's substitution of weld surface examinations into the risk-based portion of the ISI program, which required volumetric weld examinations.

Description: On April 9, 2004, while performing the baseline ISI procedure (IP 7111108), the inspectors identified that the licensee had inappropriately credited surface examination of welds in the risk-based ISI program.

By letter dated July 3, 2002, the licensee requested approval to use a risk-informed ISI program in accordance with EPRI TR-112657 as an alternative to the weld inspection program required by the ASME Code for Class 1 and 2 piping welds. The NRC approved this request under provisions allowed in 10 CFR 50.55a(3)(i) as an acceptable alternative program which would provide for a comparable level of safety. Table 4-1 of EPRI TR-112657 required volumetric examination of welds subject to all degradation mechanisms except for microbiologically induced corrosion (MIC) and outside diameter stress corrosion cracking (ODSCC). On January 17, 2003, the licensee submitted the Owners Inservice Inspection Summary Report for Unit 1 to the NRC. In this report, the licensee credited two Unit 1 safety injection (SI) system weld PT examinations, completed in September 2002, as risk-based weld examinations (SIS-04-SI-1005-25 and SIS-04-SI-1005-25B). The licensee had not identified these welds as susceptible to

MIC or ODSCC or any other degradation mechanism (e.g., weld category R1.20 from Code Case N-578-1). Therefore, by taking credit for these surface PT examinations, the licensee reduced the number of volumetric examinations for this category of welds in the risk-based ISI program. The inspectors concluded that the licensee's use of surface examinations changed the basis for the approved risk-based ISI program (EPRI TR-11267), which required volumetric examinations to detect degradation that typically originated from the inside surface of piping systems. The inspectors were concerned that substitution of surface examinations for volumetric examinations could allow unacceptable piping system weld flaws to remain in-service and render safety related systems inoperable. The licensee has entered this issue in its corrective action program.

Analysis: The licensee's performance deficiency associated with this finding is the failure to perform the required volumetric weld examinations by substitution of weld surface examinations. The inspectors concluded that the finding was greater than minor in accordance with IMC 0612, "Power Reactor Inspections Reports," Appendix B, "Issue Disposition Screening," because, if left uncorrected, the substitution of surface examinations in place of volumetric examinations could allow unacceptable piping system weld flaws to remain in service. The finding was assigned to the Mitigating System Cornerstone because the affected weld examinations identified were associated with the SI system (mitigating system) and the finding affected the Mitigating System Cornerstone objective of equipment reliability. The inspectors determined that the finding could not be evaluated using the SDP in accordance with NRC IMC 0609, "Significance Determination Process," because the SDP for the Mitigating Systems Cornerstone only applied to degraded systems/components, not to the program/process failures that could result in failure to detect degraded systems/components. Therefore, this finding was reviewed by the Regional Branch Chief in accordance with IMC 0612, Section 05.04c, who agreed with the inspectors, that this finding was of very low safety significance (Green). The inspectors' determination of very low risk was based on the fact that the licensee had sufficient time left in the Code interval to perform the required number of volumetric examinations of piping welds in the affected risk based category during future Unit 1 outages.

Enforcement: On April 9, 2004, while performing the baseline ISI, the inspectors identified an NCV of 10 CFR 50.55a(a)(3)(i).

10 CFR 50.55a(a)(3)(i) states, in part, that alternatives to requirements of paragraph 10 CFR 50.55a(g) [ASME Section XI Code] may be used, when authorized by the NRC. By letter dated July 2, 2003, in accordance with 10 CFR 50.55a(a)(3)(i), the NRC approved the licensee's use of a risk-based ISI program in accordance with EPRI TR-112657, "Revised Risk-Informed Inservice Inspection Evaluation Procedure," Revision B-A. In EPRI TR-112657, Table 4-1, volumetric examinations of welds were identified as the approved weld examination technique for all degradation mechanisms except MIC and ODSCC.

Contrary to these requirements, on January 17, 2003, the licensee took credit for surface examinations of welds SIS-04-SI-1005-25 and SIS-04-SI-1005-25B, completed in September of 2002 in their risk-based ISI program. These welds were not subject to MIC or ODSCC and, therefore, the licensee's use of weld surface examinations was contrary to requirements of EPRI TR-112657 Table 4-1. However, because of the very low safety significance of this finding and because the issue was entered into the licensee's corrective action program (CAP055529), it is being treated as an NCV, consistent with Section VI.A.1 of the Enforcement Policy. (NCV 05000266/2004003-02)

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

On June 10, 2004, the inspectors observed the operating crew performance during simulator training. The inspectors also reviewed some of the changes to the simulator model against modifications made in the plant. This observation constituted one quarterly inspection sample.

The inspectors evaluated crew performance in the areas of:

- clarity and formality of communications;
- understanding of the interactions and function of the operating crew during an emergency;
- prioritization, interpretation, and verification of actions required for emergency procedure use and interpretation;
- oversight and direction from supervisors; and
- group dynamics.

Crew performance in these areas was compared to licensee management expectations and guidelines as presented in Procedure NP 2.1.1, "Conduct of Operations," Revision 1. The inspectors evaluated the licensee's failure of the crew when two critical objectives of the scenario were not successfully completed. The inspectors confirmed that the crew received remedial training and passed a simulator exam prior to being allowed to return to shift duties.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors performed an issue/problem-oriented review of the system listed below, completing one maintenance effectiveness inspection sample. The inspectors reviewed repetitive maintenance activity to assess maintenance effectiveness, including maintenance rule activities, work practices, and common cause issues. Inspection activities included, but were not limited to, the licensee's categorization of specific issues, including evaluation of performance criteria, appropriate work practices, identification of common cause errors, extent of condition, and trending of key parameters. Additionally, the inspectors reviewed implementation of the Maintenance Rule (10 CFR 50.65) requirements, including a review of scoping, goal-setting, performance monitoring, short-term and long-term CAs, functional failure determinations associated with reviewed CAPs, and current equipment performance status.

For the system reviewed, the inspectors reviewed significant WOs and CAPs to verify that failures were properly identified, classified, and corrected, and that unavailable time had been properly calculated. The inspectors reviewed documents listed in the attachment to this inspection report to determine if minor discrepancies in the licensee's maintenance rule reports were corrected. This observation constituted one quarterly inspection sample.

Specific components and systems reviewed were:

- 125-volts direct current electrical system.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessment and Emergent Work Evaluation (71111.13)

a. Inspection Scope

The inspectors reviewed risk assessments for the following maintenance activities, completing risk assessment and emergent work control inspection samples. These observations constituted five quarterly inspection samples.

- unavailability of the RHR pump, 1P-10B, for planned maintenance and testing during the week of April 26, 2004;
- unavailability of the electric firewater pump because of unplanned maintenance during the U1R28, the week of April 18, 2004;
- unavailability of various equipment during the U1R28 refueling outage while completing Unit 2 planned maintenance during the week of May 17, 2004;
- unavailability of the G01 EDG for planned maintenance during the week of May 31, 2004; and
- unavailability of the D-106 battery for planned maintenance during the week of June 13, 2004.

During these reviews, the inspectors compared the licensee's risk management actions to those actions specified in the licensee's procedures for the assessment and management of risk associated with maintenance activities. The inspectors determined if evaluation, planning, control, and performance of the work were done in a manner to reduce the risk and minimize the duration, where practical, and that contingency plans were in place, where appropriate. The inspectors used the licensee's daily configuration risk assessment records, observations of shift turnover meetings, and observations of daily plant status meetings to determine if the equipment configurations had been properly listed, that protected equipment had been identified and was being controlled where appropriate, and that significant aspects of plant risk were communicated to the necessary personnel.

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Non-Routine Plant Evolutions and Events (71111.14)

.1 Unit 1 Shutdown for U1R28 Refueling Outage

a. Inspection Scope

On April 2, 2004, the inspectors observed the shutdown for the Unit 1 refueling outage (U1R28). The inspectors observed operator procedure use and adherence, communications, control of equipment, and response to minor equipment complications. This observation constituted one inspection sample.

b. Findings

No findings of significance were identified.

.2 Unit 2 Start-up from a Reactor Trip

a. Inspection Scope

On May 18, 2004, the inspectors observed the start-up of Unit 2 following a manual reactor trip. The Unit was tripped from 100 percent power after communications with a diver at the circulating water intake structure were lost. The inspectors observed the approach to criticality, power ascension to the point-of-adding-heat, blocking of trip circuits, operator response to an unexpected turbine trip and feedwater recirculation valve flange leak, and ascension to full power. This observation constituted one inspection sample.

b. Findings

No findings of significance were identified.

.3 Unit 1 Nozzle Dam Removal

a. Inspection Scope

On May 23, 2004, the inspectors observed operator response to mid-loop operations and steam generator nozzle dam removal. Following previous issues associated with nozzle dam installation, the inspectors scrutinized control and conduct of the evolution including communications, job planning, management of air lines to personnel bubble hoods, procedure use and adherence, coordination with the Outage Control Center, and management oversight. This observation constituted one inspection sample.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

During this inspection period, the inspectors reviewed the following operability evaluations:

- Unanalyzed Load on G-03 and G-04 EDGs;
- Trouble-Shooting after Inadvertent Letdown Isolation;
- Excore Source-Range Nuclear Instrument IN-31 Pre-amplifier Found Defective;
- Unit 1 and 2 Motor-Driven AFW Pump Flows; and
- Seismic Monitoring Operability in the North Warehouse.

These observations constituted five quarterly inspection samples.

The inspectors reviewed the technical adequacy of the operability evaluations against TS, FSAR, and other design information; determined whether compensatory measures, if needed, were taken; and determined whether the evaluations were consistent with Procedure NP 5.3.7, “Operability Determinations.” The inspectors also reviewed CAPs to determine if licensee personnel identified issues at an appropriate threshold and entered them into the corrective action program in accordance with station procedures. Documents reviewed during this inspection are listed in the attachment to this report.

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (OWAs) (71111.16)

a. Inspection Scope

The inspectors reviewed OWAs with particular focus on the method by which instructions and contingency actions were communicated to and reviewed with on-shift licensed operators. Documents reviewed during this inspection are listed in the attachment to this report. This observation constituted one inspection sample.

The inspectors completed the sample by reviewing:

- CAP053487, relating to the Alarm Response Book for control room panel 1C20A, Window 2-5, “Containment Hydrogen System Trouble,” which contained instructions directing operators to declare the wrong train out-of-service.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (PMT) (71111.19)

a. Inspection Scope

During this inspection period, the inspectors completed six quarterly inspection samples, composed of the following PMT activities:

- Fuel Assembly Core Location Mapping following U1R28 on May 2, 2004,
- Safety injection pump 1P-15B following seal replacement on May 25, 2004,
- Unit 1 'A' Steam Generator Header Drain and Trap Isolation Valve (1MS-228) Repack, on June 4, 2004,
- Unit 1 primary containment sump 'B' valve (1SI-850B) testing on May 3, 2004,
- Local Leak Rate Test of Unit 1 Containment Purge Valves on June 2, 2004, and
- Unit 1 RHR pump 1P-10B following replacement of the rotating element on May 4, 2004.

Documents reviewed during this inspection are listed in the attachment to this report. During completion of the inspection samples, the inspectors observed in-plant activities and reviewed procedures and associated records to determine if:

- testing activities satisfied the test procedure acceptance criteria,
- effects of the testing had been adequately addressed prior to the commencement of the testing,
- measuring and test equipment calibration was current,
- test equipment was used within the required range and accuracy,
- applicable prerequisites described in the test procedures were satisfied,
- affected systems or components were removed from service in accordance with approved procedures,
- testing activities were performed in accordance with the test procedures and other applicable procedures,
- jumpers and lifted leads were controlled and restored, where used;
- test data/results were accurate, complete, and valid,
- test equipment was removed after testing,
- equipment was returned to a position or status required to support the operability of the system in accordance with approved procedures,
- the impact of failed PMTs on primary containment isolation requirements were evaluated, and
- all problems identified during the testing were appropriately documented in the corrective action program.

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

.1 Routine Refueling Outage Inspection Activities

a. Inspection Scope

The inspectors observed outage activities during U1R28, conducted between April 2 and June 7, 2004. These inspection activities constituted one refueling outage inspection sample.

This inspection consisted of an in-office review of the licensee's outage schedule, safe shutdown plan and administrative procedures governing the outage, periodic observations of equipment alignment, and plant and control room outage activities. Specifically, the inspectors determined the licensee's ability to effectively manage elements of shutdown risk pertaining to reactivity control, decay heat removal, inventory control, electrical power control, and containment integrity.

The inspectors conducted in-plant observations of the following daily outage activities:

- attended outage management turnover meetings to determine if the current shutdown risk status was accurate, well understood, and adequately communicated;
- performed walkdowns of the main control room to observe the alignment of systems important to shutdown risk;
- observed the operability of reactor coolant system (RCS) instrumentation and compared channels and trains against one another;
- performed in-plant walkdowns to observe ongoing work activities; and
- conducted in-office reviews of selected issues that the licensee entered into its corrective action program to determine if identified problems were being entered into the program with the appropriate characterization and significance.

Additionally, the inspectors performed in-plant observations of the following specific activities:

- observed the control room staff perform the Unit 1 shutdown and initial cooldown;
- verified that RCS cooldown rates were within TS limits;
- observed control room staff operations during reduced inventory conditions;
- observed core unloading activities in the containment, SFP, and control room;
- observed core reload from the control room;
- observed operators align the RHR system for shutdown cooling;
- observed placement of the over-pressure protection system into operation;
- monitored a pre-job briefing for fuel handling evolutions;
- performed walkdowns of the auxiliary building to verify the placement of clearance orders on Unit 1 electrical buses, RHR systems, and SW systems;
- observed lifting and transport of the reactor vessel head in preparation for core offload;

- performed a walkdown of the control room and turbine building to verify safety-related electrical alignments following battery charger and 4-KV electrical bus routine maintenance;
- performed a closeout inspection of the Unit 1 containment including a review of the results of the emergency core cooling sump inspection that had been performed earlier by the licensee. As part of this inspection, the inspectors also assessed whether all discrepancies noted during the walkdown were recorded and corrected;
- walked down nozzle dam control panels to assess proper indications, installation, removal, and alarm functions;
- observed steam generator nozzle dam installation and removal;
- reviewed shutdown margin calculations;
- reviewed SFP cooling and SW pump configurations during partial core offload;
- reviewed reduced inventory level RCS transmitter configurations;
- reviewed the proper alignment and operation of the potential-dilution-in-progress alarm;
- reviewed the evaluation of the fuel handling bridges in containment and the SFP
- reviewed Mode change checklists (CLs) to verify that selected requirements were met while transitioning from the refueling Mode to full power operations;
- observed portions of low power physics testing and approach to criticality; and
- observed portions of the plant ascension to full power operations.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

During this inspection period, the inspectors completed inspection samples, composed of the following surveillance testing activities:

- Inservice Test (IT) 09A, Cold Start of Turbine-Driven Auxiliary Feed Pump and Valve Test (Quarterly) Unit 2 on May 31, 2004, reviewed Mode change CLs to determine if selected requirements were met while transitioning from the refueling Mode to full power operations;
- Operations Refueling Test 3B, SI Actuation with Loss of Engineering Safeguards AC (Train B) on April 4, 2004,
- IT-760, High Head SI Check Valve Full Flow Testing, on April 23, 2004,
- Operations Refueling Test 3A, SI Actuation with Loss of Engineering Safeguards AC (Train A) on April 6, 2004,
- RHR Pump Vibration testing on April 20, 2004, and
- IT-03, Low Head SI Pump and Valve Test (Quarterly), on June 22, 2004.

Documents reviewed during this inspection are listed in the attachment to this report. These observations constituted six quarterly inspection samples.

During completion of the inspection samples, the inspectors observed in-plant activities and reviewed procedures and associated records to determine if:

- preconditioning occurred;
- effects of the testing had been adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- acceptance criteria were clearly stated, demonstrated operational readiness, and were consistent with the system design basis;
- plant equipment calibration was correct, accurate, and properly documented; as-left setpoints were within required ranges; and the calibration frequency was in accordance with TSs, FSAR, procedures, and applicable commitments;
- measuring and test equipment calibration was current;
- test equipment was used within the required range and accuracy;
- applicable prerequisites described in the test procedures were satisfied;
- test frequency met TS requirements to demonstrate operability and reliability;
- the tests were performed in accordance with the test procedures and other applicable procedures;
- jumpers and lifted leads were controlled and restored where used;
- test data/results were accurate, complete, within limits, and valid;
- test equipment was removed after testing;
- where applicable for in-service testing activities, testing was performed in accordance with the applicable version of ASME Section XI, and reference values were consistent with the system design basis;
- where applicable, test results not meeting acceptance criteria were addressed with an adequate operability evaluation or the system or component declared inoperable;
- where applicable for safety-related instrument control surveillance tests, reference setting data have been accurately incorporated in the test procedure;
- prior procedure changes had not provided an opportunity to identify problems encountered during the performance of the surveillance or calibration test;
- equipment was returned to a position or status required to support the performance of its safety functions; and
- all problems identified during the testing were appropriately documented and dispositioned in the corrective action program.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors conducted in-plant observations of physical changes to the plant and equipment, performed in-office reviews of documentation, and assessed, where applicable, remote alarm capabilities to evaluate the TMs detailed below. The inspectors reviewed design basis documents (DBDs) and safety evaluation screenings to ensure that the modifications were consistent with applicable documents, drawings, and procedures. The inspectors also reviewed the post-installation results to confirm that any impacts of the TMs on permanent and interfacing systems were adequately verified. These observations constituted two inspection samples.

The inspectors reviewed the following TMs:

- Installation of Blank Flange at VNSPE-3212/3244.
- Auxiliary Feed Tunnel Seismic Event Annunciation.

b. Findings

No findings of significance were identified.

1EP4 Emergency Action Level and Emergency Plan Changes (71114.04)

a. Inspection Scope

The inspectors reviewed Revision 40 of Section 2 and Revision 46 of Section 7 of the Point Beach Emergency Plan to determine if the revisions reduced the Plan's effectiveness, pending on-site inspection of the implementation of these changes.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

.1 Emergency Plan Procedure Training Drills

a. Inspection Scope

During the weeks of June 14 and June 21, 2004, the inspectors observed the training drills involving the revised EALs and Emergency Plan Implementing Procedures. The inspectors observed classifications, notifications, facility activations, and facility critiques. The observations were in the Control Room (simulator), Technical Support Center, and Emergency Operations Facility. The inspectors also observed the training of new Emergency Response Organization personnel. This observation constituted one inspection sample.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety (OS)

2OS1 Access Control to Radiologically Significant Areas (71121.01)

.1 Plant Walkdowns and Radiation Work Permit Reviews

a. Inspection Scope

The inspectors reviewed licensee controls and surveys for selected radiation areas, high radiation areas and airborne radioactivity areas, as available, in the following radiologically significant work areas within the plant and reviewed work packages which included associated licensee controls and surveys for these areas to determine if radiological controls (including postings and barricades) were acceptable:

- Primary Auxiliary Building, and
- Unit 1 Containment (all levels).

The inspectors reviewed the radiation work permits (RWP) and work packages used to control work in these areas and other high radiation work areas to identify the work control instructions and control barriers that had been specified. Electronic dosimeter alarm setpoints for both integrated dose and dose rate were evaluated for conformity with survey indications and plant policy. Workers were interviewed to assess their knowledge of the actions required when their electronic dosimeters noticeably malfunctioned or alarmed.

The inspectors walked down these areas to determine if the prescribed RWPs, procedures, and engineering controls were in place, licensee surveys and postings were complete and accurate, and air samplers (if necessary) were properly located.

The inspectors reviewed the RWPs and surveys for the steam generator nozzle dam installation and ET activities which had the potential for creating an airborne radioactivity area. The inspectors reviewed the RWPs to determine if barrier integrity and engineering control contingency plans were in place and to determine if there was a potential for individual worker internal exposures of greater than 50 millirem committed effective dose equivalent. This and other work activities/areas having a history of, or the potential for, airborne transuranic isotopes were evaluated to determine if the licensee had considered the potential for transuranic isotopes and provided appropriate worker protection.

The inspectors assessed the adequacy of the licensee's internal dose assessment process by reviewing personnel contamination event logs (and associated dose assessments) for the refueling outage. As of April 21, 2004, no personnel contamination events had resulted in dose assignments of greater than 10 millirem committed effective dose equivalent.

These reviews represented four inspection samples.

b. Findings

No findings of significance were identified.

.2 Job-In-Progress Reviews

a. Inspection Scope

The inspectors observed the following four activities that were being performed in radiation areas, airborne radioactivity areas, or high radiation areas to assess work activities that presented the greatest radiological risk to workers:

- 1B Reactor Coolant Pump Motor Lift;
- Steam Generator ET Testing;
- Reactor Vessel Head Lift; and
- Cono-Seal Bullet Replacement.

The inspectors reviewed radiological job requirements for these four activities, including RWP and work procedure requirements, and attended as-low-as-is-reasonably-achievable (ALARA) pre-job briefings.

Job performance was observed with respect to these requirements to determine if radiological conditions in the work areas were adequately communicated to workers through pre-job briefings and postings. The inspectors also reviewed the adequacy of radiological controls (including required radiation, contamination, and airborne surveys), radiation protection job coverage (including audio/visual surveillance for remote job coverage), and contamination controls. This included a review of the radiological controls employed and resulting potential dose consequences related to the installation of steam generator nozzle dams early in the refueling outage. The inspectors completed their assessment of the nozzle dam installation activities by conducting an in-office review of the licensee's root cause evaluation (RCE) for the evolution during the week of May 24, 2004.

Radiological work in high radiation work areas having significant dose rate gradients was reviewed to evaluate the application of dosimetry to effectively monitor exposure to personnel and to determine if licensee controls were adequate. In particular, the steam generator ET activities and cono-seal bullet replacement involved evolutions where the dose rate gradients were severe, which increased the necessity of providing multiple or repositioned dosimetry and/or enhanced job controls.

These reviews represented three inspection samples.

b. Findings

Introduction: One NRC-identified Green finding and an associated NCV were identified when, on April 9, 2004, licensee staff increased supplied breathing air pressure while attempting to mitigate lost or diminished air flow to contract workers in continuous flow, supplied air respirator "bubble hoods" who were installing steam generator nozzle dams.

The increased air pressure resulted in the use of respiratory equipment contrary to 10 CFR 20.1703.

Description: On April 9, 2004, during the Unit 1 refueling outage, installation of steam generator nozzle dams commenced. The RWP for the job required the use of continuous flow, supplied air respirator "bubble hoods" for whole body entries into the steam generator bowl. At the start of the work, at least one contractor expressed a concern to RP staff about low air pressure within the hood but he subsequently entered the 'B' steam generator. After working in the steam generator for 1:48 minutes, the worker exited the generator because of continued low air flow.

The RP staff examined the quick disconnect "Snap-Tite" connection from the bubble hood hose to the regulator air hose and identified no obvious problems. Also, no problems were identified with the plant air system. Subsequently, RP supervision approved an increase in the hood air line air pressure from 20 - 28 pounds per square inch gauge (psig) to approximately 60 - 64 psig, for the 50-foot air line hose of the bubble hood. The increase of the air pressure violated Health Physics Implementing Procedure (HPIP) 4.58, Step 4.5.7, which stated, "adjust air supply pressure so that air flow is between 6 and 15 cubic feet per minute [cfm]. For an air line length of 50 feet, a pressure range of 20 to 28 psig corresponds to a flow rate of 6 to 15 cfm."

Ten minutes after the first contract worker exited the steam generator, a second contractor entered the 'B' steam generator bowl. According to the licensee's RCE, while inside the bowl (for 1:18 minutes), the contractor realized that he had lost air flow, but he continued working until he "believed he had 2 or 3 good breaths left" at which point he exited the steam generator. As with the first contractor, the second contractor was cut out of the "bubble hood" upon exiting the steam generator bowl and incurred a minor personal contamination event (PCE). The RP staff at the steam generator platform determined that the "Snap-Tite" fitting on the hood hose had disconnected, resulting in the loss of air flow. A third contractor then entered the bowl and completed the installation of the nozzle dam.

During installation of the nozzle dam in the 'A' steam generator, two additional loss of air incidents occurred. In one instance, the contractor had partially entered the bowl when the "Snap-Tite" fitting contacted the manway and disconnected. The contractor immediately exited, the air line was reconnected, and the contractor re-entered the steam generator to complete the installation. In the second instance, an air supply line pinched against and was cut by equipment staged on the platform, resulting in diminished air flow. The RP technician taped the cut air line and the worker completed his work in the bowl. Around this time, an NRC inspector who was observing the nozzle dam installation activities via video monitors raised concerns about the breathing air problems to site management. Subsequently, a formal investigation was initiated by the licensee which led to a formal root cause evaluation.

The licensee's root cause evaluation (CAP055527/RCE 253, completed May 22, 2004), detailed more than 20 inappropriate actions during the steam generator nozzle dam installation activities. In addition to the performance issues detailed above, the licensee's RCE identified that three different RP department evaluations of calendar year 2003 operating events/experience (OE), relative to the loss of supplied breathing air due to separation of air line quick disconnect fittings, had failed to adequately assess the station's susceptibility to similar occurrences. Specifically, OE031454, OE048685, and OE010321 were evaluated by the licensee but were closed for reasons including "fittings are from a different manufacturer," "fittings are taped," and "procedures and controls are adequate to minimize susceptibility to this event." However, the fittings described in the OE are of similar design as those used for bubble hood air line connections at Point Beach and no actions were taken to physically challenge the "Snap-Tite" fittings during the evaluations.

The licensee's corrective actions included: (1) a site-wide stand-down to discuss these and related events with station/contractor staff; (2) an independent team assessment of the station's procedures and processes relative to the use of supplied air respiratory devices (and implementation of procedural and equipment changes, as necessary); (3) development of a complete nozzle dam removal plan in accordance with the applicable work planning procedures; (4) full mock-up training for the nozzle dam removal, including bubble hood use and air pressure requirements; and (5) development of a specific procedure for nozzle dam installation/removal activities, including lessons-learned, supervisory oversight requirements, stop work authority, communications protocol, and external operating experience.

During the in-office review of the RCE, the inspectors identified that when the RP staff increased the air line pressure to approximately 60 psig, the resulting flow rate in the bubble hood would have exceeded 15 cfm. The National Institute for Occupational Safety and Health (NIOSH) certification requirements for continuous flow, supplied air respirator bubble hoods are described in 42 CFR Part 84, Subpart J. Specifically, Table 8 of Subpart J, requires, in part, that for the bubble hoods used during the evolution (Type C, loose fitting hood), the air supply hose with air regulating valve shall permit a flow of not less than 6 cfm, and the maximum flow shall not exceed 15 cfm. Therefore, in addition to violating station procedure HPIP 4.58, the inspectors determined that when the RP staff increased the air pressure to approximately 60 psig, the licensee used a respiratory protection device contrary to the NIOSH certification for the device, which is a violation of 10 CFR 20.1703, "Use of Individual Respiratory Protection Equipment."

<u>Analysis</u>: The inspectors determined that the licensee failed to meet the requirements of 10 CFR 20.1703, when the licensee increased the air line pressure in excess of the procedural guidance in HPIP 4.58, which resulted in the licensee utilizing a respiratory protection device contrary to its NIOSH certification. This issue could reasonably be viewed as a precursor to a significant event and, if left uncorrected, would become a more significant safety concern. Also, the issue involved conditions contrary to licensee procedures and NRC regulations which impact protective equipment related to mitigating worker dose. Therefore, the issue was determined to be more than minor and represents a finding which was evaluated using the significance determination process (SDP) for the Occupational Radiation Safety Cornerstone.

The inspectors determined utilizing Manual Chapter 0609, Appendix C, "Occupational Radiation Safety SDP," that the finding did not involve ALARA/work controls. Further, based on the inspectors' review of: (1) dose rates and contamination levels in the steam generator bowls; (2) licensee dose evaluations; and (3) worst case stay time estimates within the bowls, there were no radiological exposures in excess of regulatory limits, nor was there a substantial potential for an overexposure. Additionally, the licensee's ability to assess dose was not compromised. Consequently, the inspectors concluded that the SDP assessment for this finding was of very low safety significance (Green).

Finally, the inspectors identified that multiple cross-cutting areas were affected by these events. Specifically, the root cause of inadequate supervisory oversight and the contributing cause relative to procedure use and adherence were the result of poor human performance. The contributing cause relative to the station's use and evaluation of operating experience relates to Problem Identification and Resolution. Finally, an inadequate level of questioning attitude was exhibited by station staff relative to: (1) the cause of the apparent low air flow, and (2) the one contractor's failure to immediately leave the steam generator bowl upon loss of air.

Enforcement: 10 CFR 20.1703 requires, in part, that if a licensee permits the use of respiratory protection equipment, the licensee: (1) use only equipment that is tested and certified by the NIOSH, unless authorized by the NRC; and (2) implement and maintain a respiratory protection program that includes written procedures regarding the storage, issuance, maintenance, repair, testing, and quality assurance of respiratory protection equipment. Contrary to the above, on April 9, 2004, the licensee increased the air line pressure of the bubble hoods employed during steam generator nozzle dam installation activities, beyond the procedural requirements of HPIP 4.58, "Issuance of Respiratory Equipment," which resulted in the licensee utilizing a respiratory protection device contrary to the NIOSH certification and without NRC authorization. However, because the licensee documented this issue in its corrective action program (CAP055527/RCE 253), conducted a full evaluation into the causes of the events, and took corrective actions to address staff knowledge of procedural adherence prior to nozzle dam removal activities, and the violation is of very low safety significance, it is being treated as an NCV (NCV 05000266/2004003-03).

.3 Radiation Worker Performance

a. Inspection Scope

During job performance observations, the inspectors evaluated radiation worker performance with respect to stated radiation protection work requirements and evaluated whether workers were aware of the significant radiological conditions in their workplace, the RWP controls and limits in place, and that their performance accounted for the level of radiological hazards present.

These reviews represented one inspection sample.

b. Findings

No findings of significance were identified.

.4 Radiation Protection Technician Proficiency

a. Inspection Scope

During job performance observations, the inspectors evaluated RP technician performance with respect to radiation protection work requirements and evaluated whether they were aware of the radiological conditions in their workplace, the RWP controls and limits in place, and if their oversight of radiological activities was consistent with their training and qualifications with respect to the radiological hazards and work activities.

These reviews represented one inspection sample.

b. Findings

No findings of significance were identified.

2OS2 As-Low-As-Is-Reasonably-Achievable Planning And Controls (ALARA) (71121.02)

.1 Inspection Planning

a. Inspection Scope

The inspectors reviewed the U1R28 refueling outage work scheduled during the inspection period and associated work activity exposure estimates for the following four work activities which were likely to result in the highest personnel collective exposures:

- U1R28 RP Coverage [RWP No. 04-104];
- Bottom Mounted Instrumentation Inspection [RWP No. 04-133];
- Nozzle Dam Installation/Removal [RWP No. 04-141]; and
- Steam Generator ET Testing [RWP No. 04-142].

These reviews represented one inspection sample.

b. Findings

No findings of significance were identified.

.2 Radiological Work Planning

a. Inspection Scope

For those activities identified in Section 2OS2.1, the inspectors reviewed the ALARA evaluations, exposure estimates, and exposure mitigation requirements to determine if the licensee had established procedures, and engineering and work controls that were based on sound radiation protection principles in order to achieve occupational exposures that were ALARA.

The interfaces between radiation protection, operations, maintenance, planning, scheduling, and engineering groups were evaluated by the inspectors to identify interface problems or missing program elements. The inspectors evaluated if work activity planning included consideration of the benefits of dose rate reduction activities, such as shielding provided by water filled components/piping, job scheduling, and shielding and scaffolding installation/removal activities. Finally, the inspectors evaluated the integration of radiological job planning activities (pre-job ALARA reviews) into work procedure and RWP documents.

These reviews represented three inspection samples.

b. Findings

No findings of significance were identified.

.3 Verification of Dose Estimates and Exposure Tracking Systems

a. Inspection Scope

The inspectors reviewed the licensee's process for adjusting exposure estimates or re-planning work, when unexpected changes in scope, emergent work, or higher than anticipated radiation levels were encountered. This review included a determination if adjustments to estimated exposures (intended dose) were based on sound radiation protection and ALARA principles, rather than adjustments to account for failures to adequately control the work. The frequency of these adjustments was reviewed to evaluate the adequacy of the original ALARA planning process. In particular, the inspectors reviewed and discussed with the RP staff the in-progress ALARA reviews conducted for the bottom mounted instrumentation inspection and steam generator nozzle dam installation/removal RWPs.

These reviews represented one inspection sample.

b. Findings

No findings of significance were identified.

.4 Job Site Inspections and ALARA Control

a. Inspection Scope

The inspectors observed the four activities identified in Section 2OS1.2 that were being performed in radiation areas, airborne radioactivity areas, or high radiation areas for observation of work activities that presented the greatest radiological risk to workers. The licensee's use of engineering controls to achieve dose reductions was evaluated to determine if procedures and controls were consistent with the licensee's ALARA reviews, sufficient shielding of radiation sources was provided for, and the dose expended to install/remove the shielding did not exceed the dose reduction benefits afforded by the shielding.

These reviews represented one inspection sample.

b. Findings

No findings of significance were identified.

.5 Radiation Worker Performance

a. Inspection Scope

Radiation worker and RP technician performance was observed during work activities performed in radiological areas that presented the greatest radiological risk to workers. The inspectors evaluated whether workers demonstrated the ALARA philosophy in practice by being familiar with the work activity scope and tools to be used, by utilizing ALARA low dose waiting areas, and by complying with work activity controls. Also, radiation worker performance was observed to determine whether individual training/skill level was sufficient with respect to the radiological hazards and the work involved.

These reviews represented one inspection sample.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification (71151)

Cornerstone: Initiating Events

.1 Reactor Safety Strategic Area - Initiating Events Cornerstone

a. Inspection Scope

The inspectors reviewed the licensee’s recent PI submittal. The inspectors used PI definitions and guidance contained in Revision 2 of Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline," to determine the accuracy of the PI data. The inspectors reviewed selected applicable conditions and data from logs, licensee event reports, and CAPs from April 2002 through April 2004. The inspectors independently re-performed calculations where applicable. The inspectors also compared that information to the information required for each PI definition in the guideline, to ensure that the licensee reported the data accurately.

These observations constituted four inspection samples. The following PIs were reviewed:

Unit 1

- Unplanned Scrams per 7000 Critical Hours
- Unplanned Scrams with a Loss of Heat Removal

Unit 2

- Unplanned Scrams per 7000 Critical Hours
- Unplanned Scrams with a Loss of Heat Removal

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Identification and Resolution of Problems, Inservice Inspection Activities

a. Inspection Scope

From April 5 through 28, 2004, in an office on the 8-foot level of the TSB, the inspectors performed a review of a sample of ISI-related problems that were identified by the licensee and entered into the corrective action program. The inspectors reviewed these corrective action program documents to confirm that the licensee had appropriately described the scope of the problems. Additionally, the inspectors' review included confirmation that the licensee had an appropriate threshold for identifying issues and had implemented effective corrective actions. The inspectors evaluated the threshold for identifying issues through interviews with licensee staff and review of licensee actions to incorporate lessons learned from industry issues related to the ISI program. The inspectors performed these reviews to ensure compliance with 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements. The specific corrective action documents that were reviewed by the inspectors are listed in the attachment to this report.

b. Findings

No findings of significance were identified.

.2 Resident Inspector Routine Review of Identification and Resolution of Problems

a. Inspection Scope

As discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to determine if they were being entered into the licensee's corrective action system at an appropriate threshold, adequate attention was given to timely corrective actions, and adverse trends were identified and addressed. Minor issues entered into the licensee's corrective action system as a result of inspector observations are included in the list of documents reviewed which is attached to this report.

b. Findings

No findings of significance were identified.

.3 Resident Inspector Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a semi-annual review of licensee trending activities to determine if emerging adverse trends that might indicate the existence of a more significant safety issue were adequately identified, were entered into the licensee's corrective action system at an appropriate threshold, and timely corrective actions were implemented. The effectiveness of the licensee trending activities was assessed by comparing trends identified by the licensee with those issues identified by the NRC during the conduct of routine plant status and baseline inspections.

The inspector's review nominally considered the six-month period of January 2004 through June 2004, although some examples expanded beyond those dates when the scope of the trend warranted. The inspector's review was focused on operations and engineering human performance errors, but also considered the results of daily inspector corrective action program item screening discussed in Section 4OA2.2 above, licensee trending efforts, and licensee human performance results. This inspection effort completed one semi-annual trending inspection sample.

b. Findings and Observations

There were no findings of significance identified.

The inspectors evaluated the licensee trending methodology and observed that the licensee had performed a detailed review. The inspectors compared the licensee process results with the results of the inspectors' daily screening and did not identify any discrepancies or potential trends in the corrective action program data that the licensee had failed to identify. The significant trends identified as a result of this review included trends in the areas of Operations mis-positioning events, the number of human performance events associated with inattention to detail, implementation of the work management process, and declining performance associated with Operations internal and external communications. Trends identified in the Engineering area included the high number of mechanical and electrical design CAPs, inadequate documentation of activities, configuration control process issues, and the number of corrective action program actions being returned. The inspectors verified these trends were captured in the corrective action system. Finally, the inspectors noted that although the licensee had initiated an in-depth examination of the station scheduling activities and practices to identify potential problem areas in the first quarter of 2004, the initiative was not successful in preventing a large number of late schedule changes and adjustments immediately prior to the beginning of the U1R28 refueling outage.

.4 Resident Inspector Review of an Unexpected Unit 2 Charging Pump Trip

a. Inspection Scope

During the week of April 15, 2004, the inspectors reviewed the circumstances associated with an unexpected trip of a Unit 2 charging pump to evaluate potential repetitive equipment failures or human performance issues which might warrant additional follow-up. In addition, the inspectors reviewed the effectiveness of the CAs taken on identified issues. This observation constituted one resident inspector inspection sample

b. Findings and Observations

There were no findings of significance identified.

The inspectors reviewed the background, history, and licensee follow-up actions relating to the unexpected trip of a Unit 2 charging pump (2P-2B) on January 12, 2004. The cause of the trip was initially thought to be a failure of a drive belt, but was later traced to actuation of a protective relay (the ‘86' over-current relay). Vibrations caused by opening a ‘sprung’ breaker cabinet door, while preparing for maintenance unrelated to the charging pump, caused the actuation. Plant operators used applicable procedures to assess and make notifications regarding the event, and to promptly restore charging flow and balance it with letdown flow. The licensee’s evaluation of the event was acceptable and the ‘Fix it Now’ team was assigned to implement timely corrective maintenance. Appropriate investigative and corrective actions were initiated and an acceptable ‘extent of condition’ review was performed. No previous events were identified relating to ‘86' relays or to charging pumps, but in one previous event, a relay vibrated when a cabinet door was opened and caused an inadvertent start of an EDG. This event was properly classified as a Maintenance Rule Functional Failure as it related to charging pump 2P-2B.

.5 Resident Inspector Review of Unit 1 Outage Performance

a. Inspection Scope

From April 2 through June 8, 2004, the inspectors reviewed selected Unit 1 refueling outage events related to worker interface with operations, inattention-to-detail, adequate self-checking, control of contractors, operators awareness of TS requirements, and maintaining a critical safety focus in order to evaluate potential repetitive failures or human performance issues which might warrant additional follow-up. In addition, the inspectors reviewed the effectiveness of the CAs taken on identified issues. This observation constituted one resident inspector inspection sample.

b. Findings and Observations

Introduction: The inspectors identified a Green finding concerning the decision by several licensed and experienced personnel during U1R28 to authorize steam generator nozzle dam installation prior to the establishment of a vent path through the pressurizer manway.

Description: During the Unit 1 outage from April 2 through June 8, 2004, the inspectors observed multiple human performance issues.

Potential Loss of Hot Leg Vent Path During Nozzle Dam Installation

At approximately 4:00 a.m. on April 9, senior outage, work control center, and control personnel (including several senior reactor operators) were notified of difficulties in removing one of the bolts on the pressurizer manway. In the outage schedule, this activity preceded installation of the steam generator nozzle dams. According to the licensee, the senior personnel reviewed the schedule and operating procedure (OP) 4F, "Reactor Coolant System Reduced Inventory Requirements." From the review, the personnel concluded that the nozzle dam installation could precede while efforts to remove the pressurizer continued. The personnel, however, did not review the outage safety plan and the 10 CFR 50.59 evaluation for the nozzle dam installation procedure in which was contained a discussion of the need for the pressurizer manway removal to establish an appropriate-sized vent path prior to the complete installation of the nozzle dams.

Installation of the cold leg nozzle dams was completed and installation of the hot leg nozzle dams was in progress around 6:00 a.m., when oncoming dayshift personnel questioned the status of the manway removal. Nozzle dam installation was then halted and an investigation was begun. The licensee's investigation identified that because of a damaged bolt hole, the hot leg nozzle dam for the 'A' SG was never completely installed. A licensee engineering evaluation subsequently concluded that an adequate vent path was provided by this configuration, even with the pressurizer manway in-place.

Other Outage Human Performance Issues Affecting Multiple Disciplines

- On May 15, divers entered the intake crib to begin planned repairs. Licensee procedures required that dive boat operators be in constant telephone communications with the control room. Despite this requirement, the dive boat only communicated with the work control center on an as-needed basis. During the repairs, a diver entered the north side of the intake that housed the CW pipes for the operating Unit 2. The suction flow pulled the diver's air line and tether into the intake bell such that the diver could not free himself. According to the licensee, the licensee contractor liaison assigned to the dive crew did not exhibit positive control when informed by the contractors that they were also going to inspect the Unit 2 crib while they were on the dive. When it was noticed that the diver was being drawn into the Unit 2 CW pipes, the boat crew called the work control center and requested that the CW pumps be secured. Work control center personnel notified control room operators, who manually scrammed the Unit 2 reactor and secured the CW pumps. This manual trip of a reactor because of problems with a diver is similar to an occurrence in 2000 (Inspection Report 50-266/00-14(DRP); 50-301/00-14(DRP) and Licensee Event Report (LER) 266/2000-010). This most recent event demonstrated less than adequate control of contractors.

- A temporary change was made to Procedure OP-4F on May 19, requiring shiftly nozzle dam checks. During a procedure review three days later, the licensee noticed that the checks were not being done, a minor violation of regulatory requirements.

- On April 21, one of three incore thermocouple guides was inadvertently lifted along with the Unit 1 reactor vessel head. This left the thermocouple connections exposed and prevented refueling cavity flood up until the guide could be replaced, lengthening the reduced time-to-boil periods. Visual examinations were conducted, as required by the head lift procedure, when the head was approximately 1 foot and 4 feet above the vessel flange, however, the examinations did not identify the inadvertent lifting of the thermocouple guide. This issue represented a lack of worker attention-to-detail.

- On April 23, electrical maintenance performed a breaker alignment in preparation for an upcoming electrical bus outage. During the alignment, the person performing the breaker alignment and the peer checker both verified that the correct breaker was going to be manipulated. Both workers, however, became distracted prior to the manipulation. When the person performing the manipulation returned his attention to the task of opening the breaker, he opened the wrong breaker. Approximately three hours later, an auxiliary operator discovered that the SFP cooling flow was zero despite the ‘A’ SFP cooling pump (P-12A) having been previously operating. The auxiliary operator reported the information to the control room and the operators entered AOP-8F, “Loss of Spent Fuel Pool Cooling,” procedure. The operators identified that the breaker for P-12A was in the “OFF” position. The breaker was closed and P-12A restarted. This was an example of inadequate self-checking. No cooling temperature limits were exceeded.

- During the installation of the ‘A’ SG and ‘B’ SG nozzle dams on April 9, the inspectors observed problems with the breathing air for steam generator bowl workers. The inspectors discussed these problems with the attendant RP personnel but the problems continued. The inspectors then provided this information to licensee senior managers who stopped the nozzle dam installation work pending a review and resolution of the problems. This is discussed in section 2OS1.

- Several times during the refueling outage, contract workers entered the radiological controlled area without properly logging into an RWP. One group of contractors logged into an RWP for the primary auxiliary building and during the course of work entered primary containment without returning to access control to log into the appropriate containment RWP. During work in containment, their dosimetry alarmed because they had exceeded the dose associated with their primary auxiliary building RWP. This was an example of inadequate self-checking.

- Technical Specification 3.9.1 requires boron concentration in the RCS, the refueling canal, and the refueling cavity to be maintained within the limits specified in the core operating limits report (COLR). This surveillance was required every 72 hours, but was performed by operations every 24 hours. On April 12, with core 28 still in the reactor vessel, operations noticed that boron concentration was being verified using the COLR associated with core 29, the core that was to be installed during the refueling outage. The COLR had been replaced in the control room on April 8. The licensee immediately provided a copy of COLR 28 to the control room operators and on April 14, COLR 28 was re-issued. The boron concentration limit for COLR 28 was 2400 parts per million (ppm), and the limit for COLR 29 was 2200 ppm. The inspectors determined that the surveillance had been performed daily and boron concentration had been greater than the required 2400 ppm between April 8 and 12. This issue involved operator attention-to-detail and timely identification of Technical Specification issues. The inspectors determined that the issue was minor because the COLR 28 boron requirements were more conservative than the COLR 29 requirements.

- 120-Volt Vital Instrument Panel 1Y-04 was de-energized for planned maintenance at 10:21 p.m. on May 3, affecting the nuclear instrumentation source range audible count rate circuit. Despite procedure 1-SOP-Y-Y04, "1Y-04, Yellow 120V Vital Instrument Panel", providing guidance on affected loads and TSs, senior reactor operators on multiple shifts were not aware of the TSAC requirement to immediately isolate unborated water sources when the source range audible count circuit was inoperable. TSAC 3.9.2.C until 4:20 a.m. on May 4. This issue involved operator inattention-to-detail and timely identification of Technical Specification requirements. The issue was entered into the licensee Corrective Action Program (Activity Request CAP056363). The inspectors determined that this was minor because a review of plant conditions indicated that all unborated water sources were isolated during the event, even though the operators had not taken action to perform this requirement.

Analysis: Issues associated with the nozzle dam and hot leg vent path indicated a lack of safety focus on the part of licensed and experienced personnel such that if shutdown cooling had been lost, significant consequences may have resulted. In addition, the lack of safety focus on the part of licensed and experienced personnel was considered to affect the cross-cutting area of human performance. Despite several barriers, experienced, supervisory personnel incorrectly allowed nozzle dam installation to commence prior to pressurizer manway removal.

The inspectors determined that allowing hot leg nozzle dams to be installed before the intended pressurizer manway hot leg vent path was in place was a performance deficiency warranting a significance evaluation in accordance with IMC 0612, “Power Reactor Inspection Reports,” Appendix B, “Issue Screening,” issued on June 20, 2003. The finding was considered more than minor because it affected: (1) the Reactor Safety Initiating Events cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown operations, and (2) the human performance attribute of the Initiating Events cornerstone.

The inspectors completed a significance determination of the nozzle dam and hot leg vent path issue using IMC 0609, “Significance Determination Process,” dated March 21, 2003, Appendix G, “Shutdown Operations,” dated May 25, 2004. The inspectors determined that the finding was considered to be of very low safety significance (Green) and did not require quantitative assessment since (1) conditions meeting a loss of control were not met in that no inadvertent change in RCS temperature or change in reactor vessel level actually occurred, and (2) the licensee had maintained adequate mitigation capability for plant conditions associated with a PWR in refueling operations with a time-to-boil of less than 2 hours. The inspectors noted, however, that the mitigation capability was not achieved by intentional or controlled actions on the part of the licensee, rather, the problems with the bolt hole in the 'A' SG hot leg precluded full installation of all four nozzle dams while the pressurizer manway was still attached.

Enforcement: Because (1) the actual sequence of events showed that all four nozzle dams had not been completely installed while the pressurizer manway was still in place; and (2) an engineering analysis showed that an adequate hot leg vent path was available while one of the 'A' SG hot leg nozzle dam side pieces was not installed, no violation of regulatory requirements occurred. This issue was considered a finding of very low significance (FIN 05000266/2004003-04). The licensee entered the finding into its corrective action program as CAP055538, "Potential for No Hot Leg Vent Path during Unit 1 SG Nozzle Dam Installation."

4OA3 Event Follow-up (71153)

.1 (Closed) Licensee Event Report (LER) 50-301/2004-001-00: SI System Accumulator Operated With Fluid Level Out of Specification High.

Introduction: A Green NCV of TS Surveillance Requirement (SR) 3.5.1.2 was self-revealed when the water volume in SI accumulator 2T-34A exceeded the Technical Specification limit of 1136 cubic feet. The finding was considered self-revealing since it was indicated through a change in the functionality of the accumulator level transmitters during routine operations.

Description: SI accumulator 2T-34A was drained for maintenance on October 8, 2003, during the 2003 Unit 2 refueling outage. The two associated level transmitters were calibrated, filled, and vented while the accumulator was drained. The accumulator was re-filled on October 29, 2003, and a discrepancy was noted between level indicators 2LI-939 and 2LI-938. The level transmitters were vented and filled, and the transmitter equalizing valves were opened and closed. However, opening the equalizing valves improperly allowed water into the dry reference legs of the transmitters and introduced a bias such that the indicated accumulator level was lower than the actual level.

Upon completion of the refueling outage, Unit 2 entered Mode 3 (on November 10, 2003), when the SI accumulators were required by TSs to be operable, and subsequently resumed full power operations. On February 14, 2004, 2LI-939 was noted to be drifting lower. Troubleshooting efforts commenced and the transmitter reference leg was drained. Upon return to service, the 2LT-939 indication was high off scale. Subsequently, the transmitter was found to be out-of-calibration. On February 15, the transmitter was replaced with an on-site spare. When placed in service, the replacement transmitter again indicated high off scale. A calibration check found the output to be drifting and attempts to calibrate the transmitter were unsuccessful. On February 22, a new transmitter from the manufacturer was installed. When placed in service, the new transmitter indicated high off scale, for a third time. On March 19, 2LT-

939 was replaced with a different model level transmitter under a modification. When placed in service, the new transmitter again indicated high off scale, for a fourth time. On March 30, UT of the sensing and reference lines of both 2LT-938 and 2LT-939 identified that 2LT-939 was indicating correctly, water was present in the reference leg of 2LT-938, and the actual accumulator level had exceeded the TS limit. Immediate actions were taken to enter the applicable TS Action Condition, to restore the accumulator to operable status. A root cause evaluation was performed and an LER was submitted.

Analysis: The inspectors determined that operating with the Unit 2 'A' safety injection accumulator with levels above TS limits was a performance deficiency warranting a significance evaluation. The inspectors concluded that the finding was greater than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," issued on June 20, 2003, because it affected the Reactor Safety Mitigating Systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to prevent initiating events.

The inspectors completed a significance determination of this issue using IMC 0609, "Significance Determination Process," dated March 21, 2003, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," dated March 18, 2002. The inspectors determined that the finding was considered to be of very low safety significance (Green) since (1) the Nuclear Steam Supply System vendor performed an analysis of the over-filled, as-found condition and determined that the 2T-34A accumulator had been capable of performing the design basis function and would not have challenged the 10 CFR 50.46 Loss-of-Coolant-Accident acceptance criteria, and (2) the finding did not result in a design or qualification deficiency, an actual loss of safety function, or involve internal or external initiating events. This finding was assigned to the Reactor Safety Mitigating Systems Cornerstone for Unit 2.

Enforcement: Technical Specification 3.5.1 requires that two SI accumulators be operable in Modes 1 and 2, and in Mode 3 with RCS pressure greater than 1000 psig. Technical Specification SR 3.5.1.2 requires that borated water volume in each accumulator be verified to be greater than or equal to 1100 cubic feet, and less than or equal to 1136 cubic feet every 12 hours. Contrary to these requirements, the water volume in safety injection accumulator 2T-34A was greater than 1136 cubic feet between November 10, 2003, and March 30, 2004.

This violation was entered into the licensee's corrective action system as CAP055204 "Troubleshooting Reveals 2T34A SI Accumulator Level Out of Specification High." Because this violation was of low safety significance and it was entered into the licensee's corrective action program, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy. (NCV 05000301/2004003-05). This LER is closed.

.2 <u>(Closed) LER 50-266/2004-001-00</u>: Reactor Pressure Vessel Head Penetration 26 Flaw Indications.

During NDE Unit 1 reactor pressure vessel head, possible flow indications were observed using UT of the "J" groove weld area for control rod drive mechanism head penetration 26. To further characterize these indications, multiple PTs of the penetration 26 "J" groove weld area were performed, including PT following minor excavation of the weld surface area. The results of these examinations confirmed the existence of flaws in the "J" groove weld. On May 6, 2004, based upon preliminary analyses, the licensee determined that these indications would probably not be found acceptable under ASME Code standards. Therefore, the condition was reported under 10 CFR 50.72(b)(3)(ii)(A) as a significant degradation of a principal safety barrier. Research by the licensee on the observed UT indications concluded that they were likely the result of weld repairs during fabrication and were not related to primary water stress corrosion cracking.

The licensee conducted an extent-of-condition evaluation. The evaluation concluded that the tubing, counterbore region, and other areas of the reactor vessel head were free of defects, wastage and boric acid deposition and, therefore, the structural integrity and leak integrity of the reactor vessel head was assured. The licensee based this conclusion on:

- Review and comparison of the ultrasonic signatures obtained during the U1R27 and U1R28 underhead inspections;

- Review of available fabrication records;

- Inspection of the Alloy 600 control rod drive mechanism tubing, counterbore region and reactor vessel head in accordance with NRC Order EA-03-009; and

- Verification of the leakage integrity of the RCS boundary by visual examination of the top of the reactor pressure vessel head with no evidence of defects, wastage or boric acid crystal deposition.

A weld repair of the penetration 26 control rod drive mechanism nozzle was completed on May 22, in accordance with an approved plant modification. On June 4, the NRC approved a relaxation of the first revised order EA-03-009 regarding the upcoming Unit 1 operating cycle. This allowed removal of a Unit 1, Mode 2 restraint and authorized full power operations of Unit 1 for one operating cycle. Unit 1 achieved criticality on June 7 and returned to full power operations on June 11, 2004.

Further information concerning NRC review of the Unit 1 reactor vessel head inspection is provided in Section 4OA5.1 of this report. This LER was reviewed by the inspectors and no findings of significance were identified. This LER is closed.

.3 Unit 2 Manual Reactor Trip

a. Inspection Scope

On May 15, 2004, the inspectors observed operator response to a manual reactor trip when a diver entered the north side of the CW intake crib and could not free himself. The inspectors reviewed operator actions to trip both CW pumps immediately after the reactor was manually tripped and maintain RCS temperature using the steam generator atmospheric steam dump valves. The inspectors reviewed the event for equipment problems and ensured Unit 2 was stabilized at normal operating temperature and pressure. The inspectors observed portions of the Unit 2 restart efforts, including operator response to turbine electro-hydraulic control system malfunctions.

b. Findings

No findings of significance were identified.

4OA4 Cross-Cutting Aspects of Findings

.1 A finding described in Section 1R05.1 of this report had, as a contributing cause, a human performance deficiency, in that the licensee failed to identify transient combustible materials during tours required by the FPER and NP procedures.

.2 A finding described in Section 2OS1.2 of this report, had, as primary causes, human performance deficiencies, in that: (1) there was inadequate supervisory oversight of bubble hood use during steam generator nozzle dam installation; and (2) RP staff failed to appropriately apply the procedure for bubble hood issuance and the maximum air flow criteria.

.3 A finding described in Section 2OS1.2 of this report, had, as a contributing cause, inadequate evaluation of operating experience (an element of problem identification and resolution), in that certain quick disconnect air line fittings had recently been identified as being susceptible to inadvertently separating. However, the licensee, in its evaluations of these operating experiences, failed to physically challenge the bubble hood air fittings used at the station.

.4 A finding described in Section 4OA2.5 of this report had, as its primary cause, a human performance deficiency. Several licensed and experienced personnel incorrectly authorized the installation of steam generator nozzle dams prior to the establishment of a vent path through the pressurizer manway.

.5 A finding described in Section 4OA5.4 of this report had, as its primary cause, a human performance deficiency, in that despite problems with a software program being previously known and operations department management expectations to perform line-by-line reviews prior to distribution having been established, 16 undetected errors in emergency operating, emergency contingency action, critical safety, and shutdown emergency procedures for Units 1 and 2 existed between October 3, 2003, and July 9, 2004.

4OA5 Other Activities

.1 Reactor Pressure Vessel (RPV) Head and Vessel Head Penetration Nozzles (TI 2515/150)

a. Inspection Scope

On February 11, 2003, the NRC issued Order EA-03-009 (ADAMS Accession Number ML030410402). This order required examination of the reactor pressure vessel head and associated vessel head penetration (VHP) nozzles to detect primary water stress corrosion cracking (PWSCC) of VHP nozzles and corrosion of the vessel head. The purpose of TI 2515/150, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles," Revision 2, was to implement an NRC review of the licensee's head and VHP nozzle inspection activities required by NRC Order EA-03-009. The inspectors performed a review in accordance with TI 2515/150 of the licensee's procedures, equipment, and personnel used for examinations of the Unit 1 RPV and VHP to confirm that the licensee met requirements of NRC Order EA-03-009 (as revised by NRC letter dated February 20, 2004). The results of the inspectors' review included documentation of observations and conclusions in response to the questions identified in TI 2515/150.

From April 5 through May 26, 2004, in an office on the 8-foot level of the TSB building, (unless otherwise stated), the inspectors performed a review of the licensee's Unit 1 head inspection related activities in response to NRC Order EA-03-009. To evaluate the licensee's efforts in conducting the required examinations, the inspectors:

- performed direct visual examination of the head-to-nozzle interface for portions of 30 VHP nozzles inside the Unit 1 containment from access doors in the service structure surrounding the head;
- observed, inside the Unit 1 containment building, licensee personnel conducting a remote visual examination of the RPV head for portions of 12 VHP nozzles;
- conducted interviews with the licensee's nondestructive examination personnel performing nondestructive examinations of the vessel head in the head inspection trailer within the site protected area;
- reviewed the head inspection procedures;
- reviewed the certification records for the nondestructive examination personnel performing examinations of the vessel head;
- reviewed the procedures used for identification and resolution of boric acid leakage from systems and components above the vessel head;
- reviewed the licensee's procedures and corrective actions implemented for boric acid leakage;
- reviewed in an on-site trailer the videotaped PT examinations conducted on the VHP nozzle No. 26 J-weld;

- reviewed in an on-site trailer the videotaped cleaning and visual examination of portions of six head-to-nozzle interface areas;

- reviewed in an on-site trailer automated UT data for rotating and blade probes collected during the Unit 1 vessel head at 20 VHP nozzle locations;

- reviewed in an on-site trailer automated UT data collected for VHP nozzles No. 32 and No. 33 during the previous Unit 1 outage; and

- observed from a remote camera monitor in an on-site trailer manual UT examination of the lower portions of VHP nozzles No. 32 and No. 33.

The inspectors conducted these reviews to confirm that the licensee performed the vessel head examinations in accordance with requirements of NRC Order EA-03-009 (or Order relaxation requests), using procedures, equipment, and personnel qualified for the detection of PWSCC in VHP nozzles and detection of vessel head wastage.

From May 11 through 26, 2004, in an office on the 8-foot level of the TSB building, (unless otherwise stated), the inspectors performed a review of the licensee's repair activities for VHP nozzle No. 26. The inspectors reviewed the licensee's weld procedures, certified mill test reports for the weld materials, process traveler steps, and weld control records, and observed portions of the repair welding in the Unit 1 containment to confirm that ASME Code Section III and Section IX requirements were met (as amended by a licensee's Code relief request).

From April 5 through 28, 2004, in an office on the 8-foot level of the TSB, the inspectors reviewed the licensee's VHP nozzle susceptibility ranking calculation C11470, "Reactor Vessel Head Effective Degradation Year (EDY)," to:

- verify that appropriate plant-specific information was used as input;

- confirm the basis for the head temperature used by licensee; and

- determine if previous VHP cracks had been identified, and if so, documented in the susceptibility ranking calculation.

b. Observations

Summary

The licensee performed a remote visual examination of the top surface of the Unit 1 vessel head using a robotic crawler with a high-resolution camera supplemented with direct visual examinations to complete inspection of the 49 Unit 1 VHP nozzles and the head vent line penetration. Based upon this inspection, the licensee did not identify any leaking VHP nozzles or evidence of vessel head wastage. The licensee also conducted UT examinations for each of the 49 VHP nozzles and for the head vent line penetration nozzle. Due to limitations in UT examination coverage at the bottom end of 17 VHP nozzle locations, the licensee requested relaxation from Order EA-03-009 requirements.

The licensee also performed PT examinations of the head vent line and VHP nozzle No. 26 J-groove weld locations. During the PT examination of the VHP nozzle No. 26 J-groove weld, the licensee identified linear indications (cracks) which required repair. The licensee subsequently removed the cracked nozzle No. 26 J-groove weld and completed a temper bead weld repair.

Evaluation of Inspection Requirements

In accordance with requirements of TI 2515/150, the inspectors evaluated and answered the following questions:

1. *For each of the examination methods used during the outage, was the examination performed by qualified and knowledgeable personnel? (Briefly describe the personnel training/qualification process used by the licensee for this activity.)*

   Above Head Visual Examinations

   Yes. The licensee conducted a remote and direct visual examination of the top surface of the vessel head with knowledgeable staff members certified to Level II or Level III as VT-2 examiners in accordance with procedure NDE-3, “Written Practice For Qualification And Certification For NDE Personnel.” This qualification and certification procedure met the industry standard ANSI/ANST CP-189, “Standard for Qualification and Certification of Nondestructive Testing Personnel.” Additionally, the licensee’s VT-2 personnel had access to photographs of each penetration location taken during the last Unit 1 visual head inspection, completed in 2002.

   Under Head Automated UT Examinations

   Yes. The licensee’s vendor personnel that performed the automated UT were certified to Level II or III in UT examination in accordance with vendor (Framatome) procedure 54-ISI-30-01, “Written Practice for the Qualification and Certification of NDE Personnel.” This procedure met the industry standard ANSI/ANST CP-189, “Standard for Qualification and Certification of Nondestructive Testing Personnel.” Additionally, the licensee’s vendor UT acquisition and analysis personnel had a minimum of 16 hours training on the automated UT examination techniques used.

   Under Head Manual Ultrasonic Examinations

   Yes. The licensee conducted a manual UT examination of the lower portions of VHP nozzles No. 32 and No. 33 below the J-groove weld with a knowledgeable staff member certified to Level III as for UT examination in accordance with procedure NDE-3, “Written Practice For Qualification And Certification For NDE Personnel.” This procedure met the industry standard ANSI/ANST CP-189, “Standard for Qualification and Certification of Nondestructive Testing Personnel.”

Under Head PT Examinations

Yes. The licensee conducted a solvent removable PT examination of the head vent and penetration VHP nozzle No. 26 J-groove weld locations with a knowledgeable staff member certified to Level III in PT examination in accordance with procedure NDE-3, "Written Practice For Qualification And Certification For NDE Personnel." This procedure met the industry standard ANSI/ANST CP-189, "Standard for Qualification and Certification of Nondestructive Testing Personnel."

2. *For each of the examination methods used during the outage, was the examination performed in accordance with demonstrated procedures?*

Above Head Visual Examinations

Yes. The licensee performed a bare metal inspection of the vessel head in accordance with procedure NDE-757, "Visual Examination For Leakage of Reactor Pressure Vessel Penetrations." The licensee considered this procedure to be demonstrated because examination personnel could resolve lower case alpha numeric characters 0.158 inches in height at a maximum of 6 feet under existing lighting, which met the Code visual VT-2 examination criterion.

However, the inspectors identified parameters that could impact the quality/effectiveness of the inspection which were not controlled by the procedure. Specifically, the procedure did not provide:

- guidance for when and how to collect samples of deposits if any had been identified near the interface of lower head penetrations. Further, no guidance existed to identify what analysis would be performed to determine the source of deposits identified. Instead, the licensee staff stated that they would follow a Bottom Mounted Instrument Inspection Decision Tree Diagram to make decisions on sampling of deposits on the upper head;

- guidance or threshold for identification and documentation of corrosion or wastage (e.g., 1 percent or 10 percent wastage etc.). Note that the licensee and NRC inspectors did not identify any significant corrosion or wastage in the visual examinations of the RPV head;

- demonstration of the near distance resolution capability for the remote camera system; and

- demonstration of color resolution capability for the remote camera system.

For the items discussed above, the licensee provided verbal direction or controlled the parameters, such that the inspectors did not consider the quality of the visual examination to be compromised.

The inspectors observed licensee personnel performing the remote visual examination of the upper surface of the reactor head under the insulation using a camera mounted to a robotic crawler in accordance with procedure NDE-757 for portions of 12 vessel head VHP nozzle locations. The licensee was able to position the inspection camera within a few inches of the vessel head penetration VHP nozzle interface with sufficient lighting such that a sharp/clear visual image was obtained. The inspectors judged the resolution capability of the remote visual camera system to be very good, based upon the ability to resolve very small debris particles at the penetration nozzle-to-head interfaces.

The inspectors reviewed the licensee's demonstration of visual resolution and noted that it was consistent with the procedure requirements. The inspectors also performed a direct visual inspection for portions of 30 VHP nozzles viewable at 5 of the 6 inspection ports in the service structure. Based on this examination, the inspectors noted that the remote picture quality appeared to provide for a superior inspection to that achievable by a direct visual examination from the service structure access doors.

Under Head UT and PT Examinations

Yes. The licensee's vendor performed automated UT examinations in accordance with Framatome ANP Nondestructive Examination Procedure 54-ISI-100-11, "Remote Ultrasonic Examination of Reactor Head Penetrations." The licensee's vendor demonstrated an earlier version of this procedure on mockup VHP nozzles which contained cracks or simulated cracks as documented in EPRI MRP-89, "Materials Reliability Program Demonstrations of Vendor Equipment and Procedures for the Inspection of Control Rod Drive Mechanism Head Penetrations." The inspectors reviewed the revisions to procedure 54-ISI-100-11 implemented since the licensee's vendor had demonstrated this procedure in EPRI MRP-89, to ensure that any equipment configuration changes did not affect flaw detection capability. Additionally, the licensee's vendor had demonstrated the capability to detect a leakage path in the interference zone using this procedure on a mockup with a simulated leak path and at other nuclear power plants with observed leakage paths such as the Oconee Units. However, the inspectors noted that this UT procedure/method was not designed to detect PWSCC contained entirely within the J-groove welds of VHP nozzles.

The inspectors identified a potential weakness in the licensee's implementation of procedure 54-ISI-100-11, "Remote Ultrasonic Examination of Reactor Head Penetrations." The inspectors noted that the licensee's vendor typically ran the blade UT probe to failure which precluded a final calibration check of the failed UT probe. If the vendor had elected to incorporate the ASME Code Section XI rules into this procedure, the examination data would have been considered invalid back to the last known UT equipment calibration check. The licensee's vendor UT analyst typically accepted the UT data up to point of probe failure. This practice was allowed by the licensee's procedure; however, the inspectors concluded that it placed greater reliance on the licensee's vendor UT data analyst which could increase the probability of missing cracks due to human errors.

Unknown. The licensee conducted under head automated UT examinations of the vessel head vent line nozzle penetration in accordance with procedure 54-ISI-137-03, “Remote Ultrasonic Examination of Reactor Vessel Head Vent Line Penetrations.” The licensee’s vendor considered this procedure demonstrated based upon the ability to see electric discharge machined (EDM) notches in the UT calibration standard (reference 54-PQ-137-01, “Remote Ultrasonic Examination of Reactor Vessel Head Vent Line Penetrations”). The inspectors noted that this type of demonstration would not assure the capability of this equipment to detect PWSCC. Therefore, the inspectors could not independently confirm the ability of this equipment to detect PWSCC in the head vent line nozzle base material.

Yes. The licensee conducted manual UT examinations of the lower portions of VHP nozzles No. 32 and No. 33 below the J-groove weld in accordance with procedure NDE-141, “Manual Ultrasonic Examination of Reactor Head Penetrations.” The licensee demonstrated this procedure in a blind test on a control rod drive penetration tube mockup with EPRI. EPRI considered this procedure qualified for detection only and not for sizing of flaws. This manual UT examination did not include the J-groove weld region of VHP nozzles No. 32 and No. 33.

Yes. To detect PWSCC in the J-groove weld area of the head vent line and VHP nozzle No. 26, the licensee performed a PT examination in accordance with procedure NDE-451 “Visible Dye Penetrant Examination Temperature Applications 45 degrees Fahrenheit to 125 degrees Fahrenheit.” The licensee considered the use of an ASME Code qualified solvent removable visible PT procedure to detect surface breaking PWSCC flaws in the J-groove welds as demonstrated. This procedure allowed the licensee to use a greater temperature range over the standard band specified in Article 6, of Section V of the ASME Code. The ASME Code allows expanded temperature ranges if the procedure is demonstrated at the limits of the expanded temperature band. The inspectors confirmed that the licensee had appropriately demonstrated the procedure on a quench cracked aluminum comparator block in accordance with the ASME Code Section V, Article 6 requirements.

3. *For each of the examination methods used during the outage, was the examination able to identify, disposition, and resolve deficiencies and capable of identifying the PWSCC and/or head corrosion phenomena described in Order EA-03-009?*

Above Head Visual Examinations

Yes. The inspectors determined through direct observation of the bare metal head, interviews with inspection personnel, reviews of procedures and inspection reports, and reviews of videotape documentation that the licensee was capable of detecting and characterizing leakage from cracking in VHP nozzles.

The upper head had been cleaned during the previous outage and was relatively free of debris or deposits which would mask evidence of leakage. The inspectors performed a direct visual examination through five of six viewing ports in the service structure and observed the licensee performing the remote video inspection of the bare metal head conducted under the insulation with a camera mounted to a magnetic crawler. The licensee also supplemented the remote visual with direct visual examinations and performed frequent checks of the VT-2 visual examination quality indicator card during these examinations. Overall, the inspectors concluded that the remote visual examination resolution and picture quality equal or superior to a direct visual examination. The licensee was able to obtain a visual examination at each of the 49 VHP nozzles and the head vent line nozzle penetration, with no obstructions or interferences. Therefore, the inspectors concluded that the inspection performed was capable of detecting evidence of leakage at the VHP nozzle penetrations caused by PWSCC or corrosion of the vessel head caused by boric acid.

Under Head VHP Automated UT Examinations

Yes. For the VHP nozzle base metal material, the UT equipment, techniques and procedures had been demonstrated as effective in detection of PWSCC. The licensee used automated UT equipment with two different configurations. A blade-type UT probe was used to acquire data for sleeved VHP nozzles and relied on a single transducer pair optimized for detection of circumferentially oriented flaws using a time of flight diffraction (TOFD) UT technique. A rotating head type UT probe was used to acquire data from VHP nozzles without thermal sleeves. The rotating probe contained multiple TOFD transducer configurations and shear wave transducers which were designed to optimize detection of both circumferential and axial oriented flaws. Both the blade and rotating head UT probes were configured to detect evidence of leakage/corrosion in the interference zone behind the VHP nozzle based on the pattern in the UT backwall response. During the Unit 1 VHP examinations, the licensee's vendor identified that a rotating probe shear wave transducer failed to detect the reflectors in the calibration block during the post-examination calibration check because it was "too noisy." The licensee determined that loss of data from this one transducer had no effect on the rotation probe's ability to detect PWSCC due to the multiple transducers on the rotating probe which still functioned properly. The inspectors agreed with the licensee's evaluation that failure of this UT transducer would not affect the ability of the rotating probe to detect PWSCC.

No. The licensee's UT examination methods implemented on the VHP nozzles were not designed to detect J-groove weld cracking and, therefore, had not been demonstrated for detection of PWSCC or other flaws contained entirely within the J-groove welds. Therefore, for PWSCC contained entirely within the J-groove weld, the inspectors concluded that the licensee's UT examination method would not be effective for detection of PWSCC.

Under Head Vent Line Penetration Automated UT Examinations

Unknown. A rotating probe with pulse-echo type shear and longitudinal wave transducers was used to acquire data from the head vent line penetration. The licensee's vendor considered the UT method used on the head vent nozzle as demonstrated based upon the ability to see simulated cracks (EDM notches) in the UT calibration standard (reference 54-PQ-137-01, “Remote Ultrasonic Examination of Reactor Vessel Head Vent Line Penetrations”). The EDM process results in a uniform notch with a relatively wide air filled gap perpendicular to one surface that is readily detected by UT examination. In contrast, PWSCC gaps are very small (e.g., tight), are not uniform in nature and may not be perpendicular to the surface, which represents a more significant challenge for detection by UT examination. Therefore, the inspectors concluded that demonstration of this UT technique on EDM notches in the calibration standard was not sufficient to confirm the ability of this UT probe to detect PWSCC.

Under Head Manual UT Examinations Of VHP Nozzle No. 32 And No. 33

Yes. The licensee performed manual UT examinations of the lower portions of VHP nozzles No. 32 and No. 33 below the J-groove weld in accordance with procedure NDE-141, “Manual Ultrasonic Examination of Reactor Head Penetrations.” The licensee demonstrated this procedure during a blind test on a VHP nozzle mockup containing EDM notches at an EPRI facility. The licensee’s inspector also examined samples of VHP nozzles with PWSCC removed from the Oconee plant. The EPRI staff confirmed that the licensee’s inspector was able to detect the PWSCC flaws in the Oconee samples. Therefore, the inspector concluded that the licensee procedure was qualified for detection of PWSCC flaws in the VHP nozzle base material.

Under Head Penetration PT Examinations

Yes. The licensee conducted a PT examination of the head vent line and VHP nozzle No. 26 J-groove weld in accordance with procedure NDE-451. The inspectors observed the videotaped PT examination conducted on the head vent line penetration J-groove weld and confirmed that the licensee met Code penetrant dwell time and developer times and observed that no recordable indications were identified. For the VHP nozzle No. 26 J-groove weld, the licensee performed a series of PT examinations (with intermediate buffing/grinding steps) and confirmed two patches of multiple linear indications in the J-groove weld. The inspectors observed the videotaped PT examinations conducted on the VHP nozzle No. 26 J-groove weld that identified the two areas of small linear indications. Therefore, the inspectors concluded that the Code qualified PT examination of these J-groove welds was capable of detecting PWSCC based on identification of flaw-like indications in VHP nozzle No. 26 and based upon a review of vendor data that clearly showed the ability of Code PT examinations to detect PWSCC at other reactor sites.

4. *What was the physical condition of the reactor head (debris, insulation, dirt, boron from other sources, physical layout, viewing obstructions)?*

<u>Above Head Visual Examinations</u>

The Unit 1 vessel head insulation consisted of reflective metal insulation panels installed on a support structure over the top of the reactor head with access for visual examinations through six viewing ports in the metal service structure surrounding the top of the head. The inspectors viewed the bare metal head condition through five of these six viewing ports and considered the head condition relatively clean. The outer surface of the penetration tubes above the head generally contained a sprayed-on white mastic coating which had been applied as a sealer in the original head insulation design. The bare metal head was covered with a light gray colored coating applied by the head fabricator, which provided an adequate surface for visual resolution of boric acid deposits. The inspectors also observed portions of the licensee's visual examination and portions of videotapes of examinations completed on other shifts. The remote camera visual inspection was conducted under the insulation support structure and the as-found head condition was generally clean (free of debris, insulation, dirt). For some penetration locations, the annulus gap contained loose debris (presumed to be mastic which was scraped off the upper penetration tube housings during installation of new insulation during the last outage), which did not hinder the licensee's evaluation of the penetrations, because the licensee vacuumed, blew air, or used a soft brush to remove this loose debris. The licensee supplemented the remote camera inspection with direct visual examinations at some VHP nozzles. The licensee did not identify any obstructions which limited their visual inspection and licensee inspection personnel were able to fully examine the 49 VHP nozzles and the head vent line penetration.

The inspectors identified that the licensee had not determined if the visual examination scope would meet NRC Order EA 03-009 requirements. NRC order EA-03-009, dated February 20, 2004, required the licensee to complete a 95 percent surface area examination of the upper head including areas upslope and downslope of the service structure. The service structure and vertical insulation panels represented areas where the vessel head surface was not examined. The inspectors' questions as to the adequacy of the visual examination coverage prompted the licensee to document, in CAP056522, the need to develop a calculation to estimate the area of visual examination coverage. The licensee subsequently decided to document coverage in an internal memorandum dated May 17, 2004. In this memorandum, the licensee determined through review of drawings related to the head, head service structure, and insulation package, that the total head area not available for visual examination was 1.5 percent. The inspectors' questions as to how this number was calculated prompted the licensee to issue a new memorandum dated May 24, 2004, which documented the square inches of surface area obstructed. In this memorandum, the licensee changed the total obstructed area to 5 percent and concluded that the visual examination scope would be able to achieve the 95 percent coverage required by the Order.

5. *Could small boron deposits, as described in Bulletin 2001-01, be identified and characterized?*

Above Head Visual Examinations

Yes. Based upon the quality and scope of the licensee's visual examination, and independent direct observations, the inspectors concluded that any boron deposits characteristic of coolant leakage would have been identified (if any had been present). The inspectors noted that no boric acid deposits were found on the 49 VHP nozzles and head vent line penetration nozzle. The inspectors independently observed the remote visual examination for portions of 12 VHP nozzles and direct examinations of portions of 30 VHP nozzles and did not observe white deposits (boric acid) with characteristics (adherent popcorn-like) indicative of reactor coolant system leakage. The licensee performed a systematic inspection and documented the visual examination results for every nozzle-to-vessel interface location. No indications of head leakage were recorded.

6. *What material deficiencies (i.e., cracks, corrosion, etc) were identified that require repair?*

At VHP nozzle No. 26, the licensee's UT examination identified a circumferentially oriented indication (60 - 70 degree extent) located in the J-groove weld and which extended for 20 to 25 percent through-wall into the penetration tube. The licensee determined that this indication was likely due to original construction J-groove weld repair activities and was not considered a flaw. To confirm this conclusion, the licensee performed four PT examinations of the VHP nozzle No. 26 J-weld with intermediate buffing/grinding steps to attempt to remove axial indications. In the final PT examination the licensee identified two patches of flaw-like axial indications at the surface of the J-groove weld. One area of linear indications measured approximately 1.5 inch by 0.6 inch and the other area measured 2.5 inch by 0.6 inch. The licensee did not record the actual size, number, or spacing of these indications. The licensee documented their basis for not to perform additional PT examinations of other J-groove welds in an internal memorandum dated May 13, 2004, and letter to the NRC dated May 23, 2004.

The licensee decided to repair VHP nozzle No. 26, based upon the PT examination results which identified linear indications in the J-groove weld. The licensee's repair technique involved removal of the lower portion of the VHP nozzle up through the existing J-groove weld and installation of a new temper bead weld that overlapped a portion of the existing J-groove weld. The licensee performed this new temper bead weld repair in accordance with vendor traveler, "Ambient ID Temper Bead Repair for CRDM [Control Rod Drive Mechanism] Nozzles," and the welding occurred in accordance with weld procedure specification (WPS) 5S-WP3/43/ F43TBSCA301. The inspectors reviewed the certified mill test reports for the weld filler materials, process traveler steps, weld control records and observed portions of the machine operator repair welding to confirm ASME Code Section III and Section IX requirements (as amended by the licensee's Code relief request) were met. Additionally, the inspectors performed independent calculations of weld heat input for weld passes No. 1 through No. 3, to confirm that weld heat input remained within 10 percent of that qualified in accordance with Code Case N-638 requirements. The inspectors also reviewed final weld UT examination records to confirm that no flaws were identified in the VHP nozzle No. 26 repair weld.

The licensee's vendor used non-structural attachment (tack) welds on the existing J-groove weld at VHP nozzle No. 26 to mount tooling used in machining and welding. The inspectors identified that the repair process traveler steps did not include a PT examination following removal of this tack weld as required by the ASME Code Section III, paragraph NB-4435. Initially, the licensee staff considered that the existing J-groove weld was no longer part of the pressure boundary and, therefore, did not consider the ASME Code Section III requirements to apply. However, based upon followup discussions with the inspectors and NRR staff, the licensee staff submitted a supplement to the relief requests for VHP nozzle No. 26 (MR 02-018-1 and MR 02-018-2) on May 21, 2004, to request relief and to justify this deviation from Code requirements. By phone conference held on May 26, 2004, NRR staff granted the licensee verbal approval to use this relief request. The inspectors considered this violation of the ASME Code to be of minor significance, because it involved an issue of regulatory compliance, which did not have any potential safety significance.

7. *What, if any, impediments to effective examinations, for each of the applied methods, were identified (e.g., centering rings, insulation, thermal sleeves, instrumentation, nozzle distortion)?*

Above Head Visual Examinations

None.

Under Head PT Examination of Head Vent Line and VHP Nozzle No. 26

None.

Under Head Ultrasonic Examinations

NRC Order EA-03-009 dated February 20, 2004, required licensee's to scan to at least 1 inch below the lowest point at the toe of the J-groove weld for each penetration and all areas with greater than 20 ksi (1,000 pounds per square inch) tension residual and normal operating stress. For 17 VHP nozzle locations, the licensee was not able to obtain at least a full 1 inch below the J-groove weld. For these nozzles, the maximum extent volumetrically scanned at the tube outside diameter below the downhill side of the weld was less than the 1 inch due to the short length of nozzle existing below the J-groove weld and the UT transducer configuration. Specifically, the axially aligned transducer pair used on the blade probe resulted in a small volume of uninspected tube material at the inside corner of these sleeved VHP nozzle locations. On conference calls with

NRR and Region-based staff held on May 6, 2004, and May 11, 2004, the licensee discussed their intent to justify this limitation in a relaxation request to the NRC Order EA-03-009 using a deterministic fracture mechanics approach which assumed the uninspected area contained flaws. On May 14, 2004, the licensee issued a letter requesting relaxation to Order EA-03-009, which identified the 17 VHP nozzles to which this condition applied.

For VHP nozzles No. 32 and No. 33, the licensee was not able to get full 360 degree UT examination coverage with the blade UT probe due to nozzle distortion which created an insufficient clearance gap between the thermal sleeves and VHP nozzles. The licensee had similar inspection problems with these locations during the last Unit 1 outage and had to replace these thermal sleeves to allow access during the previous outage. The licensee determined that this previous replacement work would complicate another thermal sleeve removal and reinstallation activity which would be necessary to support additional UT examination coverage. The extent of uninspected area below the J-groove welds for VHP nozzles No. 32 and No. 33 was 42 degrees and 306 degrees respectively. The licensee also identified an additional 60 degrees of uninspected area in and above the J-groove weld for VHP nozzle No. 33. On conference calls with NRR and Region-based staff held on May 6, 2004, and May 11, 2004, the licensee discussed their intent to further justify this limitation in a supplemental relaxation request to the NRC Order EA-03-009. On May 14, 2004, the licensee completed additional manual UT examinations on the lower end of VHP nozzles No. 32 and No. 33 such that the examination coverage required by the Order was met for VHP nozzle No. 32. On May 14, 2004, the licensee issued a letter requesting relaxation to Order EA-03-009, for the limited UT coverage on VHP nozzle No. 33 which included a deterministic fracture mechanics analysis approach to support continued operation. On May 19, 2004, the licensee elected to remove the thermal sleeve from VHP nozzle No. 33 to permit access for the rotating UT probe to complete the examination coverage for VHP nozzle No. 33 rather than pursue the request for Order relaxation. On May 20, 2004, the licensee completed the rotating UT probe examination for VHP nozzle No. 33, such that this VHP nozzle no longer required relaxation from Order EA-03-009 requirements.

8. *What was the basis for the temperatures used in the susceptibility ranking calculation, were they plant-specific measurements, generic calculations, (e.g., thermal hydraulic modeling, instrument uncertainties), etc.?*

NRC Order EA-03-009 required licensee's to calculate the susceptibility category of each reactor head to PWSCC-related degradation. The susceptibility category in EDY established the basis for the licensee to perform appropriate head inspections during each refueling outage. The licensee documented the Unit 1 RPV head EDY in calculation C11470, "Reactor Vessel Head Effective Degradation Year (EDY)." In this calculation, the licensee used the formula required by NRC Order EA-03-009 and determined the EDY for each operating Unit. As of April 1, 2004, Unit 1 was at 15.5 EDY which placed this Unit in the high susceptibility category. The inspectors also reviewed the examination records from the previous Unit 1 head examinations and confirmed that no PWSCC of VHPs had been previously identified.

NRC Order EA-03-009 also required the licensee to have used best estimate values in determining the susceptibility category for the vessel head. The inspectors reviewed Table 2-1 of EPRI MRP-48, "PWR Materials Reliability Program Response to NRC Bulletin 2001-01," which documented operating head temperatures of 559 through 592 degrees Fahrenheit over the operating life of Unit 1. The current operating head temperature was identified as 592 degrees Fahrenheit in MRP-48 and this value had been used in the licensee's susceptibility ranking calculation. The inspectors questioned the licensee staff as to the source of the head temperature used in MRP-48, which prompted the licensee to document additional information obtained from their vendor. In a memorandum to file dated April 22, 2004, the licensee documented that an upper head bulk mean fluid temperature of 591.6 degrees Fahrenheit had been calculated by the licensee's vendor using a proprietary THRIVE computer model. This model was used to produce a range of head temperatures based on vessel core inlet operating temperatures. The temperature for the Point Beach Unit 1 head was determined by graphical interpolation from the THRIVE computer runs. Therefore, the inspectors concluded that the licensee had used a combination of plant specific information and a generic analytical model to determine operating head temperatures for Point Beach Unit 1.

9. *During non-visual examinations, was the disposition of indications consistent with the guidance provided in Appendix D of this TI? If not, was a more restrictive flaw evaluation guidance used?*.

The inspectors determined that this question was not applicable, because the licensee did not identify any flaws that required evaluation and return to service.

10. *Did procedures exist to identify potential boric acid leaks from pressure-retaining components above the vessel head?*

Yes. The licensee performed inspections of components within containment to identify leakage which included the area above the vessel head. This inspection was conducted by Operations and Maintenance Department personnel during the conduct of the reactor coolant system leakage test in accordance with procedure 1-PT-RCS-1 "Reactor Coolant System (RCS) Pressure Test-Inside/Outside Containment Unit 1." The licensee stated that this procedure was implemented four to five weeks prior to the outage with the plant at power to complete an "as-found" leakage inspection, but the scope at this point did not include areas above the reactor head. The licensee implemented this procedure a second time just after plant shutdown and once again just prior to plant startup from the refueling outage. During the two inspections with the plant shutdown, the licensee's inspection scope included areas above the reactor head. The licensee's staff were required to document indications of boric acid or active leakage (none were identified) on evaluation sheets of Appendix C of the Boric Acid Leakage and Corrosion Monitoring Program. The overall division of responsibilities and integrated actions to address boric acid leakage was identified in NP 7.4.14, “Boric Acid Leakage and Corrosion Monitoring,” and the Boric Acid Leakage and Corrosion Monitoring Program.

11. *Did the licensee perform appropriate follow-on examinations for boric acid leaks from pressure retaining components above the vessel head?*

    Not applicable. The licensee did not identify any instances of active boric acid leakage from components above the Unit 1 head. The inspectors independently reviewed data records of leakage identified during the last Unit 1 RCS leakage tests to confirm that no indications of boric acid leakage were recorded for areas near the reactor vessel head. Additionally, the NRC had confirmed that no evidence of boric acid leakage had contacted the Unit 1 head during the prior outage bare metal head examination (reference NRC inspection report 50-266/02-13; 50-301/02-13).

c. <u>Findings</u>

No findings of significance were identified.

.2 <u>Reactor Pressure Vessel Lower Head Penetration Nozzles</u> (TI 2515/152)

a. <u>Inspection Scope</u>

On August 21, 2003, the NRC issued Bulletin 2003-02, “Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity.” The purpose of this Bulletin was to: (1) Advise pressurized water reactor (PWR) licensees that current methods of inspecting the vessel lower heads may need to be supplemented with additional measures (e.g., bare-metal visual inspections) to detect reactor coolant pressure boundary leakage; (2) request PWR addressees to provide the NRC with information related to inspections that have been or will be performed to verify the integrity of the reactor vessel lower head penetrations, and; (3) require PWR addressees to provide a written response to the NRC in accordance with 10 CFR 50.54(f).

The objective of TI 2515/152, “Reactor Pressure Vessel Lower Head Penetration Nozzles,” was to support the NRC review of licensees’ vessel lower head penetration inspection activities that were implemented in response to Bulletin 2003-02. The Point Beach licensee had committed to perform a bare metal inspection of the lower vessel head for Unit 1 in response to the NRC Bulletin 2003-02. The inspectors performed a review in accordance with TI 2515/152, Revision 0, of the licensee’s procedures, equipment, and personnel used for reactor vessel lower head penetration examinations to confirm that the licensee met commitments associated with Bulletin 2003-02. The results of the inspectors’ review included documenting observations and conclusions in response to the questions identified in TI 2515/152.

From April 5 through 23, 2004, in an office on the 8-foot level of the TSB (unless otherwise stated), the inspectors reviewed activities associated with licensee inspection of the Unit 1 lower vessel head. Specifically, the inspectors:

- performed a direct visual examination inside the Unit 1 containment from a staging platform under the reactor vessel of the nozzle-to-head interface for portions of each of the 36 bottom head penetrations;

- interviewed nondestructive examination personnel in the head inspection trailer within the site protected area;

- reviewed the lower head visual inspection procedure NDE-757, "Visual Examination For Leakage of Reactor Pressure Vessel Penetrations;"

- reviewed the certification records for the nondestructive examination personnel;

- reviewed the licensee's procedure for certification of visual examination personnel; and

- reviewed visual examination and evaluation of indication records.

b. Observations

Summary

Based upon a bare metal direct visual examination of the lower head, the licensee did not identify evidence of reactor coolant system leakage near the instrument nozzle penetrations. One quadrant of the vessel at the 270 to 360 degrees azimuth had evidence of corrosion stains that were caused by rundown from liquid sources above the bottom of the vessel. The licensee believed that these stains were caused by condensed moisture corrosion of the vessel support steel. A few penetrations in this quadrant were contacted by this rust stain, but did not result in debris/deposits in the nozzle-to-head interface.

Evaluation of Inspection Requirements

In accordance with requirements of TI 2515/152, the inspectors evaluated and answered the following questions:

a. For each of the examinations methods used during the outage, was the examination:

1. Performed by qualified and knowledgeable personnel? (Briefly describe the personnel training/qualification process used by the licensee for this activity.)

Yes. The licensee conducted a direct visual examination of the Unit 1 lower vessel head penetration interface and lower vessel head surface for leakage or boric acid deposits with knowledgeable staff members certified to Level III as VT-2 examiners. One examiner was a licensee staff member certified to licensee procedure NDE-3, "Written Practice For Qualification And Certification For NDE Personnel," and the other was a licensee contractor certified to the contractors' procedure 2-NDES-001, “Nondestructive Examination Personnel Qualification and Certification.” These qualification and certification procedures met the industry standard ANSI/ANST CP-189, “Standard for Qualification and Certification of Nondestructive Testing Personnel.” Additionally, the VT-2 examination personnel had reviewed photographs of the boric acid deposits indicative of penetration leakage found at the South Texas Nuclear Power Plant.

2. *Performed in accordance with demonstrated procedures?*

Yes. The licensee performed a bare metal inspection of the lower head in accordance with procedure NDE-757, “Visual Examination For Leakage of Reactor Pressure Vessel Penetrations.” The licensee considered this procedure to be demonstrated because their examination personnel could resolve the lower case alpha numeric characters 0.158 inches in height at a maximum of 6 feet under existing lighting to meet the Code VT-2 inspection criterion.

The inspectors identified lack of procedure guidance which could potentially impact the quality/effectiveness of the inspection. Specifically, the procedure did not provide:

- guidance for when and how to collect samples of deposits if any had been identified near the interface of lower head penetrations. Further, no procedure guidance existed to identify what analysis would be performed to determine the source of deposits identified. Instead, the licensee staff stated that they would follow a Bottom Mounted Instrument Inspection Decision Tree Diagram to make decisions on sampling of deposits on the lower head;

- guidance or threshold for identification and documentation of corrosion or wastage (e.g,. 1 percent or 10 percent wastage etc.). Note that the licensee and NRC inspectors did not identify any significant corrosion or wastage in the visual examinations of the vessel head; or

- useful orientation and penetration numbering figure/schematic for the bottom mounted instrument (BMI) penetrations. Specifically, the procedure used a top down schematic vice a bottom up picture (actual view that the licensee’s visual examiners were presented with) and the BMI numbers marked by examination personnel did not match the designated numbers on vendor drawings. The licensee had physically marked each penetration with numbers (1 through 36) to assist in the lower head examination.

The inspectors performed an independent direct bare metal visual examinations for most of the 36 lower head penetration nozzles from the platform under the vessel head used by licensee's inspection staff. The inspectors determined that each penetration was readily accessible such that the licensee's inspection staff were able to conduct the visual examination from within a few inches of each penetration location. Additionally, the inspectors reviewed a sample of licensee photographs taken at each penetration nozzle. Based upon this inspection and interviews with the licensee's inspection staff, the inspectors did not identify any concerns associated with implementation of the visual inspection procedure for the lower head.

3. *Able to identify, disposition, and resolve deficiencies?*

Yes. The lower vessel head at the 270 to 360 degree (south) quadrant contained corrosion stains in a pattern that suggested a flow of liquid had run down from a source above. This flow pattern impacted several lower head penetrations. In most cases this flow pattern did not reach the BMI head-to-nozzle interface because of a raised metal pad that extended for several inches around the surface of the lower vessel head at each penetration. Based upon the visual examination, the licensee did not identify any penetration nozzles with deposits at the nozzle-to-head interface, indicative of boric acid leakage.

4. *Capable of identifying pressure boundary leakage as described in the bulletin and/or vessel lower head corrosion?*

Yes. The inspectors performed a direct visual inspection of portions of the 36 lower BMI penetration nozzles. Based on this examination, and interviews with licensee examiners, the inspectors concluded that the visual examination was capable of detecting deposits indicative of pressure boundary leakage and head corrosion as described in the bulletin.

b. *Could small boric acid deposits representing reactor coolant system leakage as described in the Bulletin 2003-02, be identified and characterized, if present by the visual examination method used?*

Yes. If small boric acid deposits characteristic/indicative of leakage had existed, the inspectors concluded that the licensee’s examination would have identified these. However, the licensee did not identify any boric acid deposits indicative of leakage.

c. *How was the visual inspection conducted (e.g., with video camera or direct visual by examination personnel).*

Licensee personnel conducted a direct visual examination of each of the lower head penetration nozzles. This examination included a bare metal visual examination of the lower head up to the transition to the vertical vessel shell wall. The licensee's inspection staff also reported looking for evidence of boric acid deposits or head corrosion during this inspection.

d. *How complete was the coverage (e.g., 360 degrees around the circumference of all the nozzles)?*

The licensee's visual examination coverage included a 360 degree unobstructed view of each of the 36 lower head penetration nozzles at the interface of the vessel head. Because the lower insulation was removed, the entire lower head was accessible to the licensee staff for the visual examination.

e. *What was the physical condition of the vessel lower head (e.g., debris, insulation, dirt, deposits from any source, physical layout, viewing obstructions)? Did it appear that there are any boric acid deposits at the interface between the vessel and the penetrations?*

The Point Beach Unit 1 lower head was surrounded by mirror-type insulation. The original insulation configuration conformed with the contour of the lower vessel dome with a 3-inch gap between the vessel and insulation. Each BMI penetration had a slight gap that varied in size and was normally covered by metal flashing. For the Unit 1 visual examination, this insulation had been removed to provide unobstructed access to the BMI penetrations. The licensee intended to install a revised lower head insulation structure with a tub-type configuration (e.g., horizontal insulation floor with vertical walls). This revised insulation design provided for access doors in the vertical and horizontal walls to allow access for future bare metal head inspections.

On the lower head, the inspectors observed scattered patches of what the licensee staff believed was a corrosion-resistant coating applied to the vessel head by the original fabrication vendor prior to installation. The remnants of this coating did not interfere with the inspection. The lower vessel at the 270 to 360 degree quadrant contained corrosion and stains in a pattern that suggested a flow of liquid had run down from a source above the lower head.

f. *What material deficiencies (i.e., crack, corrosion, etc.) were identified that required repair?*

None. The licensee did not identify any boric acid deposits indicative of leakage and, therefore, no repairs were required.

g. *What, if any, impediments to effective examinations, for each of the applied nondestructive examination method, were identified (e.g., insulation, instrumentation, nozzle distortion)?*

None. The direct visual examination required access to the vessel lower head and BMI nozzle penetrations by climbing down a ladder, into the keyway (a sump area under the vessel). This area was a confined space, a high radiation area, and was congested by the instrument tubes and their supports. Scaffold had been installed to support removal of the lower insulation and to allow access for direct inspection of the BMI penetrations. With the insulation removed, each penetration was accessible from this platform for direct visual inspection.

h. *Did the licensee perform appropriate follow-on examinations for indications of boric acid leaks from pressure-retaining components above the vessel lower head?*

The licensee did not identify indications of boric acid leakage from pressure-retaining components above the lower head.

i. *Did the licensee take any chemical samples of the deposits? What type of chemical analysis was performed (e.g., Fourier Transform Infrared), what constituents were looked for (e.g., boron, lithium, specific isotopes), and what were the licensee's criteria for determining any boric acid deposits were not from RCS leakage (e.g., Li-7, ratio of specific isotopes, etc.)?*

Not applicable. The licensee did not identify any boric acid deposits on the lower head and, therefore, did not perform any chemical samples.

j. *Is the licensee planning to do any cleaning of the head?*

Yes. The licensee staff stated that the lower head would be cleaned with deionized water, rags, and scotch-bright pads prior to reinstalling the lower head insulation.

k. *What are the licensee's conclusions regarding the origin of any deposits present and what is the licensee's rationale for the conclusions?*

The licensee did not identify any deposits on the Unit 1 lower head. The inspectors questioned the licensee staff as to the source of the corrosion stains at the 270 to 360 degree quadrant on the head in a pattern that suggested a flow of liquid had run down from a source above the lower head. The licensee staff stated they believed that this flow pattern was the result of condensed moisture which had run down the side of the vessel from corrosion occurring on the vessel support steel. The licensee had not been able to visually confirm the source of these rust contrails due to the narrow gap between the vessel wall and mirror insulation.

In July of 2003, the licensee identified boric acid deposits at the lower head insulation seams and where the BMI tubes penetrated the insulation (reference CAP034123). The licensee concluded that the leak source for these deposits was the sand box covers or top hat covers in the refueling cavity (e.g., refueling water seal leakage) and that this leakage would not likely contact the vessel. The licensee had chemically tested the boric acid found on the lower head insulation seams and based on the absence of lithium confirmed that source of boric acid deposits was not reactor coolant leakage.

.3 (Closed) Unresolved Item URI 50-266/03-09-01: On September 16, 2003, the licensee's vendor identified that, during the Unit 1 vessel head UT inspection completed in September 2002, the rotating UT probe head stalled due to coupling slippage which resulted in partial data acquisition in 10 of the 19 VHP nozzles (reference Framatome NCR 6028873-Lack of UT Coverage During U1 Refueling Outage No. 27 Head

Inspection). The licensee documented this issue in the corrective action system as corrective action CA053202 and condition evaluation CE012362. The licensee's vendor implemented corrective actions, which included a redesigned coupling on the rotating UT probe and use of backup analysts to prevent recurrence prior to using this tool during the Unit 2 VHP examinations. Additionally, the licensee performed an analysis of the coverage limitations and determined that there was sufficient Unit 1 data for the examination results to remain valid. The licensee subsequently performed UT of the affected VHP nozzles during U1R28 and no flaws were identified by UT. The inspectors did not identify any violations of NRC requirements for this issue and this URI is considered closed.

c. Findings

No findings of significance were identified.

.4 Reactor Containment Sump Blockage (NRC Bulletin 2003-01, Point Beach Units 1 & 2) (TI 2515/153)

a. Inspection Scope

The inspectors performed a preliminary review of licensee activities in response to NRC Bulletin 2003-01, "Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized Water Reactors (PWRs)," in accordance with NRC TI 2515/153, "Reactor Containment Sump Blockage (NRC Bulletin 2003-01)," dated October 3, 2003. The inspectors reviewed the licensee's completed and proposed compensatory measures submitted in accordance with Bulletin 2003-01, Option 2, to verify they have been implemented or were planned and scheduled for implementation consistent with the licensee's response.

Visual inspections of the containment sumps, sump screens and flow paths were performed by the inspectors during the refueling outage. The inspectors also walked down the Units 1and 2 containments to verify that the condition of the containment coatings, piping insulation, post Loss-of-Coolant-Accident (LOCA) drainage paths, and Emergency Core Cooling System (ECCS) recirculation sumps were consistent with condition reported in station documents. The inspectors interviewed operating and engineering personnel and reviewed training records, procedures for foreign material control and containment inspection, and the results of containment coating and debris generation inspections.

b. Findings

b.1 TI Reporting Requirements

No findings of significance were identified relative to the potential impact of debris blockage on emergency sump recirculation. The following information is provided as called for in the Reporting Requirements section of TI 2515/153.

During this inspection period Point Beach Unit 2 had completed an October 2003 refueling outage (Unit 2 refueling outage number 26) and subsequently returned to power. During that refueling outage a containment walkdown to quantify potential debris sources was conducted by the licensee. The walkdown conducted on Unit 2 checked for gaps in the sump screen and for major obstructions in the containment upstream of the sump.

During this inspection period Point Beach Unit 1 was in a refueling outage (Unit 1 refueling outage number 28). A containment walkdown to quantify potential debris sources was conducted by the licensee during the refueling outage. The walkdown conducted on Unit 1 checked for gaps in the sump screen and for major obstructions in the containment upstream of the sump.

The licensee is making advance preparations for the installation of new sump strainers, should it be found necessary. The preparations consist of evaluating the conceptual design of new sump strainers, including calculation of ECCS net positive suction head following debris accumulation, and an evaluation of downstream effects from suction ingestion of debris.

b.2 Failure to Control Unit 1 Emergency Operating Procedure (EOP) Sub-Steps

Introduction: The inspectors identified an NCV of 10 CFR Part 50, Appendix B, Criterion VI, "Document Control," associated with Unit 1 emergency operating procedures when a software error, that deleted two of five indications intended to monitor primary containment sump performance during the recirculation phase of a design basis accident, went undetected for a period of approximately nine months.

Description: While reviewing the licensee's 60-day response to Bulletin 2003-01, the inspectors noted that the licensee had revised EOPs to include indications to be monitored for containment sump performance and the required actions to be taken if sump blockage developed. Specifically, the licensee revised EOPs to monitor: (1) containment sump level, (2) RHR Pump Operation - NORMAL, (3) SI Pump Operation - NORMAL, (4) Low Head Injection Flow - STABLE, and (5) High Head Injection Flow - STABLE. The licensee included these indications in the Unit 1 and 2 EOPs by adding Step 29c to EOP 1, "Loss of Reactor or Secondary Coolant," Revision 34.

While reviewing EOP-1, Revision 35, however, the inspectors discovered that only three of the five parameters were described in EOP-1, Step 29c, for Unit 1 while the corresponding Unit 2 EOP continued to list all five indications. Specifically, the inspectors identified that the RHR Pump Operation - NORMAL and SI Pump Operation - NORMAL sub-steps were missing from Unit 1, EOP-1, Step 29c, Revision 35.

The Point Beach main control room boards contain RHR discharge pressure, SI pump discharge pressure, and SI pump motor amperage loading meters, parameters that would provide indications of loss of containment sump recirculation capabilities and be used to evaluate normal RHR and SI pump operations. The difference between the Unit 1 and 2 EOP procedures was determined to have been caused by the applicability function within the software program for the affected substeps having been turned off.

Since this was a known problem and had been previously documented in the corrective action program during September 2003, the Operations department expectation was to perform a line-by-line review of EOP revisions to ensure all applicable steps and substeps were included prior to delivering the procedure to document control personnel for distribution. In the case of EOP-1, Revision 35, Step 29c, for Unit 1, however, the operations review failed to identify that the substeps associated with RHR Pump Operation - NORMAL and SI Pump Operation - NORMAL had been deleted. In response to the issue, the licensee issued temporary procedure change 2004-0643 to replace the missing substeps in Unit 1, EOP-1, step 29c.

As a result of the inspector's finding, the licensee performed an extent-of-condition review of all other EOPs, emergency contingency action (ECA), critical safety procedure (CSP), and shutdown emergency procedures (SEP) for Units 1 and 2. Fifteen other cases where the software program had deleted safety-related procedure steps without operations review having identified the error prior to distribution were identified. While 14 of the errors were level-of-detail discrepancies involving, for example, missing valve numbers, one procedure had a missing response-not-obtained (RNO) column step. Specifically, Unit 2 safety-related ECA procedure 3.2, "SGTR [Steam Generator Tube Rupture] With Loss of Reactor Coolant - Saturated Recovery Desired," Revision 28, Step 17b, RNO was missing the operator actions for RCS subcooling being less than desired with RCS temperature greater than 350 degrees Fahrenheit. The inspectors determined that the result of the missing RNO step would be a delay in recovery actions and the potential unnecessary cycling of an SI pump. The licensee issued temporary procedure change 2004-0648 to replace the missing action on the same afternoon the Unit 2 ECA 3.2 error was identified. The inspectors determined that none of the errors would have impacted the ability to perform an intended safety function.

Analysis: The undetected software error allowed safety-related EOP, ECA, CSP, and SEP procedures to be issued with unauthorized changes in that the deleted substeps were not reviewed by the Plant Operating Review Committee. The inspectors determined that issuing the procedures for operator use while not being aware of deleted steps during the document revision process was a performance deficiency warranting a significance evaluation in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Disposition Screening," issued on June 20, 2003. The inspectors determined that the finding was more than minor because it affected the procedure quality attribute of the Mitigating Systems cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events. The inspectors determined that the issue also affected the cross-cutting area of human performance. Despite the problem with the software being previously known and operations expectations to perform line-by-line reviews to ensure all applicable steps were in the procedures prior to distribution, 16 EOP, ECA, CSP, and SEP procedure errors occurred.

The inspectors completed a significance determination of this issue using IMC 0609, "Significance Determination Process," dated March 21, 2003, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," dated March 18, 2002. The inspectors determined that the finding did not result in a design or qualification deficiency, an actual loss of safety function, or involve internal or external initiating events. Therefore, the finding was considered to be of very low safety significance (Green).

Enforcement: Appendix B, Criterion VI, of 10 CFR Part 50, "Document Control," requires, in part, that measures shall assure that documents, including changes, are reviewed for adequacy, approved for release, and are distributed to the location where the prescribed activity is performed. Contrary to this requirement, between October 3, 2003, and July 9, 2004, two sub-steps associated with monitoring primary containment sump performance during the recirculation phase of a design basis accident were deleted by a software error. Specifically, the inspectors identified that, although approved by the plant operating review committee and intended for distribution, the RHR Pump Operation - NORMAL and SI Pump Operation - NORMAL portions of Unit 1 emergency operating procedure EOP-1, "Loss of Reactor or Secondary Coolant," Step 29c, Revision 35, were deleted by the software program and not detected by operations personnel.

This violation was entered into the licensee's corrective action system as CAP05785, "Vendor Program Applicability Problems Deleted Monitored Parameters for Sump Blockage." Because this violation was of very low safety significance and it was entered into the licensee' s CAP, this violation is being treated as an NCV consistent with Section VI.A. of the NRC Enforcement Policy. (NCV 05000266/2004003-06) This issue and the results of the licensee's extent-of-condition review that identified 15 additional errors did not represent an immediate safety concern.

.5 Spent Fuel Material Control and Accounting at Nuclear Power Plants (TI 2515/154)

a. Scope

The inspectors completed Phase I and Phase II of the subject TI and provided the appropriate documentation to NRC management as required by the TI.

b. Findings

No findings of significance were identified.

.6 Offsite Power System Operational Readiness (TI 2515/156)

a. Scope

The inspectors reviewed licensee event reports, CAPs, procedures, and other documents; interviewed engineering, operations, and other personnel; and walked down pertinent equipment in the main control room and in the switchyard to collect data necessary to complete TI 2515/156, “Offsite Power System Operational Readiness,” dated April 29, 2004. This review was conducted to confirm the operational readiness of the offsite power systems in accordance with NRC requirements, such as Appendix A to 10 CFR Part 50, General Design Criterion 17, or similar requirements; Criterion XVI of Appendix B to 10 CFR Part 50, Point Beach TSs for offsite power systems; 10 CFR 50.63, “Loss of All Alternating Current;” 10 CFR 50.65(a)(4), “Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants;” and licensee procedures. Specifically, the inspectors reviewed the licensee's procedures and processes for ensuring that grid reliability conditions were appropriately assessed during periods of maintenance in accordance with 10 CFR 50.65(a)(4). The inspectors also assessed the reliability and grid performance through a review of historical and current data to verify compliance with the station blackout rule 10 CFR 50.63, TSs, and General Design Criterion 17 (Point Beach was a pre-Appendix A plant, but had a similar requirement). Finally, the inspectors assessed the licensee's implementation of operating experience that was applicable to the site, as well as CAPs, to ensure issues were being identified at an appropriate threshold, assessed for significance, and then appropriately dispositioned. Documents reviewed for this TI are listed in the attachment to this inspection report.

b. Findings

No findings of significance were identified. Based on the inspection, no immediate operability issues were identified and Point Beach was operationally ready for the summer of 2004 regarding the offsite grid. In accordance with TI 2515/156 reporting requirements, the inspectors provided the required data in the TI work sheets to the NRC headquarters staff for further analysis. A summary of the responses of Point Beach to the questions of the TI is provided below.

1. *What is the nature of the agreement between Point Beach and the regional transmission organization?*

   The agreement is a formal contract, "Generation - Transmission Interconnection Agreement between American Transmission Company, LLC [ATC] as Transmission Provider and Wisconsin Electric Power Company for the Point Beach Plant Interconnection Facilities," dated November 1, 2000.

2. *What voltage information has been transmitted by Point Beach to ATC?*

   The agreement incorporated several Point Beach procedures that specified offsite power 345-KV bus limits and timeliness of notification by ATC to Point Beach. The agreement included the operating voltage, shutdown voltage, and post-trip load. The operating and shutdown voltage range specified in the procedure was normal: 351 - 358 KVs; preferred: 352 - 354 KVs; and absolute, for operability of 345-KV: 348.5 - 362 KVs. The range was such that initiation of the degraded voltage relay timer was avoided. American Transmission Company automatically calculated post-trip voltages every 5 minutes, automatically following the trip of any transmission breaker (equal to or higher than 115 KVs), as requested by Point Beach personnel, and on ATC's own initiative.

3. *What type of communication exists between Point Beach and ATC?*

   In the event of a problem on the grid, ATC would call the Point Beach control room via a direct telephone line within 15 minutes, per a procedure incorporated into the contract, but according to an ATC representative, in practice, the call would be immediately.

4. *How are current grid conditions factored into the licensee's maintenance rule activities?*

Prior to testing or extensive maintenance on the EDGs, the licensee assesses current grid conditions but does not address potential post-contingency grid conditions. Included in this assessment was a review of local weather conditions: there was no seasonal restriction on EDG testing but it was not conducted during severe weather. The licensee also notified ATC of testing and extensive maintenance of the EDGs. The licensee accounted for a loss of offsite power (LOOP) for the 10 CFR 50.65(a)(4) pre-maintenance review but did not always assume it would occur. The licensee's risk modeling did not credit any recovery of offsite power.

Risk management actions were not required but were available for use by the operating crew. Many of these actions were listed in Attachment D of Procedure NP 10.3.7, "On-Line Safety Assessment," Revision 8, which included an action to minimize work in the switchyard. A similar consideration was provided in procedure NP 10.3.6, "Outage Safety Review and Safety Assessment," Revision 11. Access to the switchyard was jointly controlled by security and the control room. The station's work control and system engineering groups coordinated switchyard work activities. Station procedure NP 2.1.5, "Electrical Communications, Switchyard Access and Work Planning," Revision 3, specifically governed switchyard activities.

The licensee's offsite power system (the 345-KV system) was scoped in the Maintenance Rule as risk significant. The boundaries included the Unit 1 and Unit 2 main (output) step-up transformers (1X01 and 2X01) on the side of the switchyard closest to the plant, the five breakers associated with the four offsite power lines coming in on the side of the switchyard farthest from the plant, and various bus sections, breakers, motorized disconnect switches, and circuit switches in-between. As part of the licensee's review of this TI, it was identified that the basis for the five breakers on the four offsite lines being in or out-of-scope had not been documented. This issue was entered into the corrective action program as CAP056406, "Boundary of 345 KV System for Maintenance Rule Not Documented."

5. *How does the LOOP information in the TI compare to previous station blackout (10 CFR 50.63) information?*

The information listed in the TI for the six LOOP events at Point Beach in the last 20 years was accurate except for some minor corrections and clarifications. No conflict with the licensee's station blackout information was identified.

6. *Has the licensee entered the August 14, 2003, eastern United States and Canada grid disturbance into its corrective action system?*

Yes. The licensee evaluated the event as industry operating experience after it was entered into the corrective action program on December 8, 2003. The event was tracked as CAP052189, "SEN 242 Loss-of-Grid Event, August 14, 2003."

The licensee evaluated the event from the perspective of its impact on the emergency response facilities and organization, such as availability of flashlight batteries and backup power for computers, ventilation, and other equipment associated with the emergency operations facility. Corrective actions as appropriate were taken.

4OA6 Meetings

.1 Exit Meeting

On July 16, 2004, the resident inspectors presented the inspection results to Mr. Dennis L. Koehl and members of his staff, who acknowledged the findings. The licensee did not identify any information, provided to or reviewed by the inspectors, as proprietary.

.2 Interim Exit Meetings

Interim exits were conducted for:

- an Emergency Preparedness inspection with Ms. M. Ray on April 13, 2004.
- a Heat Sink inspection with Mr. J. Connolly on May 16, 2004.
- an Occupational Radiation Safety ALARA and access control programs inspection with Mr. G. Van Middlesworth on April 23, 2004. A re-exit to discuss the finding relative to bubble hood use was conducted telephonically on July 9, 2004, with Mr. J. Shaw.
- TI 2515/150, TI 2515/152, and the ISI procedure (IP 71111.08) inspections with Mr. J. Shaw on April 23, April 28, and May 26, 2004. The licensee confirmed that none of the potential report input discussed was considered proprietary.

4OA7 Licensee-Identified Violation

The following violation of very low significance (Green) was identified by the licensee and is a violation of NRC requirements which met the criteria of Section VI of the NRC Enforcement Manual, NUREG-1600, for being dispositioned as an NCV.

10 CFR 26.20(e) requires, in part, that procedures ensure that persons called in to perform an unscheduled working tour are fit to perform the task assigned. In addition, the procedure must (1) require a statement to be made by a called-in person as to whether he or she has consumed alcohol within the length of time stated in the pre-duty abstinence policy, and (2) address other factors that could affect fitness-for-duty. On April 7, 2004, the licensee identified that, contrary to this requirement, the automatic call-in system did not ensure that the appropriate statements were made regarding fitness-for-duty for emergency responders. The licensee entered the condition in the corrective action program as CAP055425, “Callout Process Does Not Meet Requirements of 10CFR26.20(e)(1).”

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee
J. Brander, Maintenance Manager
B. Carberry, Radiation Protection - ALARA
G. Casadonte, Fire Protection Coordinator
J. Connolly, Regulatory Affairs Manager
B. Dungan, Operations Manager
C. Hill, Assistant Operations Manager
M. Holzmann, Nuclear Oversight Manager
P. Holzman, Heat Exchanger Engineer
R. Hopkins, Internal Assessment Supervisor
B. Jensen, Level III
C. Jilek, Maintenance Rule Coordinator
B. Kemp, Reactor Vessel Head Engineer
T. Kendall, Program Engineering
D. Koehl, Site Vice-President (June 2004 to end of inspection period)
B. Kopetsky, Security Coordinator
C. Krause, Senior Regulatory Compliance Engineer
R. Ladd, Fire Protection Engineer
K. Locke, Regulatory Specialist
J. McCarthy, Site Director of Operations
R. Milner, Business Planning Manager
T. Petrowsky, Design Engineer Manager
M. Ray, Emergency Preparedness Manager
C. Richardson, Design Engineer
P. Russell, Site Assessment Manager
D. Schoon, Production Planning Manager
J. Schroeder, Service Water System Engineer
M. Schug, Assistant Operations Manager
J. Schweitzer, Site Engineering Director
J. Shaw, Plant Manager
G. Sherwood, Engineering Programs Manager
C. Sizemore, Training Manager
P. Smith, Operations Training Supervisor
J. Strharsky, Planning and Scheduling Manager
S. Thomas, Radiation Protection Manager
R. Turner, Inservice Inspection Coordinator
G. Van Middlesworth, Site Vice-President (until June 2004)
K. Zastrow, Root Cause Assessment Coordinator, Kewaunee Nuclear Plant

Nuclear Regulatory Commission
H. Chernoff, Point Beach Project Manager, NRR
P. Louden, Chief, Reactor Projects, Branch 7

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000266/2004003-01	NCV	Loss of Transient Combustible Control in the Containment and Turbine Buildings During a Unit 1 Refueling Outage (Section 1R05)
05000266/2004003-02	NCV	Substitution of Weld Surface Examinations for Volumetric Examinations (Section 1R08)
05000266/2004003-03	NCV	Failure to Follow Procedures in the Issuance and Use of Bubble Hood-type Respiratory Protective Devices (Section 2OS1.2)
05000266/2004003-04	FIN	Potential Loss of Hot Leg Vent Path During Nozzle Dam Installation (Section 4OA2.5)
05000301/2004003-05	NCV	Safety Injection System Accumulator Operated With Fluid Level Above Technical Specification Surveillance Requirement Limits (Section 4OA3.1)
05000266/2004003-06	NCV	Failure to Control Unit 1 Emergency Operating Procedure Sub-Steps Committed to as Compensatory Measures in Accordance With NRC Bulletin 2003-01, Option 2 (Section 4OA5.4)
05000301/2004001-00	LER	SI System Accumulator Operated With Fluid Level Out Of Specification High (Section 4OA3.1)
05000266/2004001-00	LER	Reactor Pressure Vessel Head Penetration 26 Flaw Indications (Section 4OA3.2)

Closed

05000266/2004003-01	NCV	Loss of Transient Combustible Control in the Containment and Turbine Buildings During a Unit 1 Refueling Outage (Section 1R05)
05000266/2004003-02	NCV	Substitution of Weld Surface Examinations for Volumetric Examinations (Section 1R08)
05000266/2004003-03	NCV	Failure to Follow Procedures in the Issuance and Use of Bubble Hood-type Respiratory Protective Devices (Section 2OS1.2)
05000266/2004003-04	FIN	Potential Loss of Hot Leg Vent Path During Nozzle Dam Installation (Section 4OA2.5)

05000301/2004003-05	NCV	Safety Injection System Accumulator Operated With Fluid Level Above Technical Specification Surveillance Requirement Limits (Section 4OA3.1)
05000266/2004003-06	NCV	Unit 1 Emergency Operating Procedure Sub-Steps for Containment Sump (Section 4OA5.4)
05000301/2004001-00	LER	SI System Accumulator Operated With Fluid Level Out Of Specification High (Section 4OA3.1)
05000266/2004001-00	LER	Reactor Pressure Vessel Head Penetration 26 Flaw Indications (Section 4OA3.2)
05000266/2003009-01	URI	Partial Data Acquisition Due To Coupling Slippage (Section 4OA5.3)

Discussed

None.

LIST OF DOCUMENTS REVIEWED

1R01 Adverse Weather

AOP-13C; Severe Weather Conditions; Unit 0, Revision 14

CAP032792; Entered AOP-13C Due to High Winds; dated May 11, 2003

CAP033403; Emergency Plan Implementing Procedure 1.1 Course of Actions Entered Due to AOP 13C Severe Weather; dated June 8, 2003

CAP057358; Training Needed to Support Station Readiness for Severe Weather Conditions; dated June 11, 2004

Periodic Check (PC) 49 Part 6; Securing From Cold Weather; Unit 0, Revision 13

1R04 Equipment Alignment

OP 71; Placing RHR System in Operation; Revision 42

CAP055691; Reactor Vessel Level Requirements per GL 88-17; dated April 14, 2004

OP 4F; RCS Reduced Inventory Requirements; Revision 19

OP 4D; Draining the RCS; Revision 62

Tag-Out Sheet; 1 OP-4D Part 1 RVLIS Ops; Revision 1-1

Westinghouse Drawing 541F091 Sheet 2, RCS P&ID [Pipe and Instrument Diagram]

1R05 Fire Protection

Fire Hazard Analysis Report (FHAR), Fire Zone 505; Containment - Unit 1 - 8 ft.; January 2003

FHAR, Fire Zone 511; Containment - Unit 1 - 21 ft.; January 2003

FHAR, Fire Zone 516; Containment - Unit 1 - 46 ft.; January 2003

FHAR, Fire Zone 520; Containment - Unit 1 - 66 ft.; January 2003

FHAR, Fire Zone 263; South Service Building - First Floor; January 2003

Fire Protection Evaluation Report; Revision 2

FHAR; Revision 1

Point Beach Nuclear Plant - Fire Area Analysis Summary Report, January 2003

NP 1.9.6; Plant Cleanliness and Storage; Revision 11

NP 1.9.9, Transient Combustible Control; Revision 6

CAP056427; NRC Questions on Combustible Material Control in Containment; dated May 5, 2004

CAP057055; Concerns Over Management of Transient Combustible Loading During U1R28; dated May 27, 2004

FHAR, Fire Zone 304, Fire Area A23, AFW Pump Room; January 2003

Calculation M-09334-357-HE.1, Appendix K, Effects of Fire Wall Addition in AFW Pump Rooms on HELB [High Energy Line Break] Results; Revision 2

CAP054382; OM [Operations Manual] 3.27 Fire Rounds Not Initiated @ 30 days as Required by Procedure; dated March 2, 2004

CAP051647; Non-Conservatism in Design Methodology For Loss Of RCP [Reactor Coolant Pump] Seal Cooling; dated November 6, 2003

CA053746; Non-Conservatism in Design Methodology For Loss Of RCP Seal Cooling; dated November 10, 2003

OM 3.27; Control of Fire Protection & Appendix R Safe Shutdown Equipment; Revision 24

1R07 Heat Sink Performance

HX-01; Condition Assessment Program; Revision 1

GL 89-13 Program Document; Revision 3

Design Basis Document (DBD) 30; Containment Heating and Ventilation; Revision 2

TS Test 33; Containment Accident Recirculation Fan-Cooler Units (Monthly) Unit 1; Revision 25

TS Test 34; Containment Accident Recirculation Fan-Cooler Units (Monthly) Unit 2; Revision 30

Operating Instruction (OI) 130; Performance Test of 1HX-15D1-D8 Containment Fan Cooler Unit 1; Revision 6

OI 131; Performance Test of 2HX-15D1-D8 Containment Fan Cooler Unit 2; Revision 7

CAP055143; HX Program Document Update Issues; dated March 26, 2004

Calculations

Calculation 98-0051; SW System HX-55 A/B Flow Requirements; Revision 2

Calculation N-94-059; CCW, HX-012A-D, SW Flow Versus Temperature Requirements; Revision 1

Calculation 2003-007; CCW Tube Plugging and Stabilization Criteria; Revision 0

Calculation 2003-008; CCW HX Plugging Limit; Revision 1

Calculation 2003-0037; Diesel Cooler Lakegrass Fouling Acceptance Criteria; dated September 5, 2003

Calculation PGT-2000-1382; Point Beach Nuclear Plant CCW HXs HX-012C and HX-012D Thermal Performance Test Data Evaluation and Uncertainty Analysis; Revision 1

Calculation PGT-2002-1270; Point Beach Nuclear Plant CCW HXs HX-012C and HX-012D Thermal Performance Test Data Evaluation and Uncertainty Analysis; Revision 0

Drawings

Drawing Number D-9643; CCW HX; Atlas Industrial Manufacturing Co.; Revision 4

Drawing Number D-322730; HX Equip. #1 and 2, HX-55A1 and B1; Young Radiator Co.; dated May 3, 1990

Condition Reports Reviewed During the Inspection

CAP011404; Significant Amount of Silt in Seal and Baseplate Leakage - SW Pumps; dated January 25, 2000

CAP001861; Diesel Cooler Fouling; dated January 14, 2002

CAP028437; G-01 Diesel Cooler Zebra Mussel and Lake Weed Fouling; dated June 11, 2002

CAP029092; G-02 Diesel Cooler Fouling; dated August 20, 2002

CAP030353; Continuing G0-2 Diesel Cooler Fouling; dated December 9, 2002

CAP030499; Major G0-1 Diesel Cooler Fouling; dated December 19, 2002

CAP033365; G0-2 Diesel Cooler Fouling; dated June 6, 2003

CAP033890; G0-2 Diesel Cooler Fouling; dated July 2, 2003

CAP034365; G0-2 Diesel Cooler Fouling; dated July 28, 2003

CAP0500040; G0-1 Diesel Cooler Fouling and G0-2 Concerns; dated September 10, 2003

CAP050119; G0-2 Diesel Cooler Fouling - Post Operability Determination Required; dated September 11, 2003

CAP051874; Significant G0-2 Diesel Cooler Fouling Past Operability Determination Required; dated November 17, 2003

CAP051944; G0-1 Diesel Cooler Fouling; dated November 20, 2003

CAP052753; G02 EDG H/X-055B-1 & HX-055B-2 Inspection Results; dated January 12, 2004

CAP053209; Jan 04 G0-1 Diesel Cooler Fouling; dated January 26, 2004

CAP053569; G0-1 Diesel Cooler Fouling; dated February 5, 2004

CAP053900; Feb 13 G0-1 Diesel Cooler Fouling; dated February 16, 2004

CAP054615; March G0-2 Diesel Cooler Fouling; dated March 9, 2004

CAP054789; Mar 14 G0-1 Diesel Cooler Fouling; dated March 15, 2004

CAP055100; Mar 25 G0-1 Diesel Cooler Fouling; dated March 25, 2004

CAP055182; Mar 29 G0-2 Diesel Cooler Fouling; dated March 29, 2004

CAP055905; April 19 G0-1 Diesel Cooler Fouling; dated April 20, 2004

CAP056354; May 3 G0-2 Diesel Cooler Fouling; dated May 3, 2004

CAP056853; May 18 G0-1 Diesel Cooler Fouling; dated May 20, 2004

CAP057186; June 3 G0-2 Diesel Cooler Fouling; dated June 3, 2004

Condition Reports Written as a Result of the Inspection

CAP057330; GL 89-13 2002 Annual Report Never Written; dated June 10, 2004

CAP057403; Revise GL 89-13 2002 Program Document; dated June 15, 2004

CAP057406; OI-151 Procedure Compliance; dated June 15, 2004

CAP057409; FSAR Section 9.6 Contains Outdated Information on Zebra Mussel Control; dated June 15, 2004

CAP057420; ARB Actions Inconsistent With OI-70 Att. B for Low SW Flow to G01/G02 H/Xs; dated June 16, 2004

Other (OTH) 013682; Calculation 98-0051 Typographical Error; dated June 15, 2004

Operability Determinations

Condition Report CR-00-0267; Revision 1; dated March 17, 2000

MRE000147; Significant G0-2 Diesel Cooler Fouling Past Operability Determination Required; dated December 12, 2003

Apparent Cause Evaluations (ACEs)

ACE001157; Apparent Cause Evaluation of CAP030619 and CAP030640; dated February 7, 2003

ACE001657; K-3A Service Air Compressor SW Strainer Found Plugged With Grass; dated April 21, 2004

Procedures

OI 70; SW System Operation; Revision 49

Alarm Response Book (ARB) C02 D 3-6; G-01 Emerg Diesel Cooler Low Flow; Revision 5

ARB C02 F 3-1; G-02 Emerg Diesel Cooler Flow Low; Revision 9

System Operating Procedure 1-SOP-CC-001; Component Cooling System; Revision 11

Chemistry Analytical Methods and Procedures 917; Copper Ion Generator; Revision 6

HX-01; Condition Assessment Program; Revision 2; dated May 18, 2004

HX-01; Condition Assessment Program, Appendix C, Unit 1 Outage Cycle Inspection Schedule; Revision 1; dated February 25, 2004

HX-01; Condition Assessment Program, Appendix D, Unit 2 Outage Cycle Inspection Schedule; Revision 1; dated February 25, 2004

HX-01; Condition Assessment Program, Appendix E; Annual Cycle Inspection Schedule; Revision 1; dated February 25, 2004

AM 3 -19; Biofouling Control Program; Revision 1

NP 7.7.15; Biofouling Control Methods; Revision 1

Diesel Generator CH01; Zebra Mussel Tracking and Evaluation; Revision 0

CD 5.25; GL 89-13 Standard; Revision 0

Completed Inspections/Surveillance Procedures

Completed Bio/Silt Fouling Inspection Forms for Diesel Generator HXs HX-055A-1 and HX-055A-2; dated various between March 18, 2003, through June 14, 2004

Completed Bio/Silt Fouling Inspection Forms for Diesel Generator HXs HX-055B-1 and HX-055B-2; dated various between August 20, 2002, through June 3, 2004

Completed Miscellaneous HXs Cleaning and Inspection Program, Appendix A; HX Internal Visual Inspection CL for HX-12C; dated August 19, 2002

Completed OI 151; HX-012C and D Component Cooling System HX Data Collection; dated October 15, 2000

Completed OI 151; HX-012C and D Component Cooling System HX Data Collection; dated April 14, 2002

Miscellaneous

Heat Exchanger Specification Sheet; Component Cooling HX; dated February 24, 1992

System Health Report SW; dated January 30, 2004

System Health Report SW; dated April 13, 2004

System Health Report; CCW System; dated January 8, 2004

System Health Report; Diesel Generator System; dated April 23, 2004

System Health Rating Status - CW; dated May 2004

Performance Criteria Assessments for CC since 6/1/2001; dated June 3, 2004

Performance Criteria Assessments for Diesel Generator since 6/1/2001; dated June 3, 2004

Performance Criteria Assessments for SW since 6/1/2001; dated June 3, 2004

DBD-02; Component Cooling System Design Basis Document; Revision 4

DBD-10; RHR System Design Basis Document; Revision

DBD-12; SW System Design Basis Document; Revision 6

DBD-16; EDG System Design Basis Document; Revision 4

FSAR Section 9.1; CCW; dated June 2003

FSAR Section 9.6; SW System; dated June 2002

FSAR Appendix A; Shared System Analysis; dated June 1998

FSAR Change Request FCR 04-007; dated February 3, 2004

TS 3.7.7; CCW System and Associated Bases B 3.7.7; Unit 1 - Amendment No. 201; Unit 2 - Amendment No. 206

TS 3.7.8; SW System and Associated Bases B 3.7.8; Unit 1 - Amendment No. 201; Unit 2 - Amendment No. 206

SW System Operational Performance Inspection; dated October 6, 1993

TIN No. 97-1177, Revision 1; Test Protocol Wisconsin Electric Power Company Point Beach Nuclear Plant CCW HX; dated January 17, 2001

PBSA-ENG-03-02; Component Cooling Water System Self-Assessment; dated September 8, 2003

GL 89-13 Annual Report for 2001; dated March 22, 2002

Point Beach GL 89-13 Program - 2003 Annual Report; dated March 22, 2004

Point Beach GL 89-13 Program Self-Assessment # PBSA-ENG-03-15; dated December 23, 2003

Program Health Status; SW/Microbiologically Induced Corrosion; dated May 21, 2004

Program Health Status; HX Safety Related NRC GL 89-13; dated May 28, 2004

GL-89-13 Program Document; Revision 3

2003 EVAC Treatment Effectiveness Report; dated September 29, 2003

Zebra Mussel Program Effectiveness Report - Annual; dated November 13, 2003

4th Quarter 2003 SW System Maintenance Rule Summary; dated January 15, 2004

GL 89-13 Program; 2003 SW System Engineer Report; dated February 13, 2004

Response to GL 89-13, Safety Related SW Problem Point Beach Nuclear Plant; dated January 12, 1990

Work Orders

WO9912379; Component Cooling HX-012C; dated January 5, 2001

WO0206227; Component Cooling HX-012C; dated August 28, 2002

WO9925508; G-01 EDG Coolant HX (East); dated May 29, 2001

WO9934401; G-01 EDG Coolant HX (East); dated August 1, 2001

WO9940300; G-01 EDG Coolant HX (East); dated May 25, 2001

WO9935151; G-01 EDG Coolant HX (East); dated June 20, 2002

WO0205750; G-01 EDG Coolant HX (East); dated July 3, 2002

WO0207039; G-01 EDG Coolant HX (East); dated December 26, 2002

WO0300008; G-01 EDG Coolant HX (East); dated March 24, 2003

WO0300015; G-01 EDG Coolant HX (East); dated May 28, 2003

WO0300017; G-01 EDG Coolant HX (East); dated November 11, 2003

WO0300018; G-01 EDG Coolant HX (East); dated December 6, 2003

WO0301022; G-01 EDG Coolant HX (East); dated January 14, 2003

WO0303667; G-01 EDG Coolant HX (East); dated June 18, 2003

WO0303668; G-01 EDG Coolant HX (East); dated July 21, 2003

WO0303674; G-01 EDG Coolant HX (East); dated September 11, 2003

WO0310370; G-01 EDG Coolant HX (East); dated January 11, 2004

WO0310371; G-01 EDG Coolant HX (East); dated February 21, 2004

WO9925507; G-01 EDG Coolant HX (West); dated May 29, 2001

WO9934400; G-01 EDG Coolant HX (West); dated August 1, 2001

WO9935150; G-01 EDG Coolant HX (West); dated June 20, 2002

WO9940299; G-01 EDG Coolant HX (West); dated May 25, 2001

WO0205749; G-01 EDG Coolant HX (West); dated July 3, 2002

WO0207037; G-01 EDG Coolant HX (West); dated December 26, 2002

WO0300007; G-01 EDG Coolant HX (West); dated March 24, 2003

WO0300012; G-01 EDG Coolant HX (West); dated September 2, 2003

WO0300013; G-01 EDG Coolant HX (West); dated November 11, 2003

WO0300014; G-01 EDG Coolant HX (West); dated December 6, 2003

WO0301023; G-01 EDG Coolant HX (West); dated January 14, 2003

WO0303662; G-01 EDG Coolant HX (West); dated June 18, 2003

WO0310360; G-01 EDG Coolant HX (West); dated January 11, 2004

WO0310361; G-01 EDG Coolant HX (West); dated February 21, 2004

WO9926689; G-02 EDG Coolant HX (East); dated August 14, 2000

WO9926693; G-02 EDG Coolant HX (East); dated October 3, 2000

WO9927125; G-02 EDG Coolant HX (East); dated July 18, 2000

WO9927420; G-02 EDG Coolant HX (East); dated February 19, 2002

WO9934403; G-02 EDG Coolant HX (East); dated August 1, 2001

WO9936321; G-02 EDG Coolant HX (East); dated February 4, 2002

WO9938065; G-02 EDG Coolant HX (East); dated February 25, 2002

WO0205752; G-02 EDG Coolant HX (East); dated September 6, 2002

WO0207043; G-02 EDG Coolant HX (East); dated December 11, 2002

WO0216411; G-02 EDG Coolant HX (East); dated March 17, 2003

WO0216412; G-02 EDG Coolant HX (East); dated June 12, 2003

WO0216413; G-02 EDG Coolant HX (East); dated October 21, 2003

WO0216414; G-02 EDG Coolant HX (East); dated November 9, 2003

WO0301037; G-02 EDG Coolant HX (East); dated January 14, 2003

WO0303672; G-02 EDG Coolant HX (East); dated July 8, 2003

WO0303673; G-02 EDG Coolant HX (East); dated July 29, 2003

WO0310390; G-02 EDG Coolant HX (East); dated February 21, 2004

WO9934402; G-02 EDG Coolant HX (West); dated August 1, 2001

WO9936367; G-02 EDG Coolant HX (West); dated February 4, 2002

WO9938063; G-02 EDG Coolant HX (West); dated February 25, 2002

WO0205751; G-02 EDG Coolant HX (West); dated January 16, 2002

WO0207041; G-02 EDG Coolant HX (West); dated December 11, 2002

WO0216406; G-02 EDG Coolant HX (West); dated March 17, 2003

WO0216407; G-02 EDG Coolant HX (West); dated June 13, 2003

WO0216408; G-02 EDG Coolant HX (West); dated October 21, 2003

WO0216409; G-02 EDG Coolant HX (West); dated November 19, 2003

WO0301038; G-02 EDG Coolant HX (West); dated January 15, 2003

WO0303669; G-02 EDG Coolant HX (West); dated July 8, 2003

WO0303670; G-02 EDG Coolant HX (West); dated July 29, 2003

WO0303852; G-02 EDG Coolant HX (West); dated April 1, 2003

WO0310380; G-02 EDG Coolant HX (West); dated February 21, 2004

WO0310381; G-02 EDG Coolant HX (West); dated May 18, 2004

WO0310384; G-02 EDG Coolant HX (West); dated May 18, 2004

1R08 Inservice Inspection Activities

Documents Associated with Two Types of Nondestructive Testing

RC-03-PS-1001-14; Primary ISI Isometric PBNP [Point beach Nuclear Plant] Unit 1 Pressurizer Spray From Loop A; Revision 2

Point Beach Nuclear Plant Ultrasonic Calibration Record; RC-03-PS-1001-14; dated April 6, 2004

Point Beach Nuclear Plant Ultrasonic Piping Examination Record; RC-03-PS-1001-14; dated April 6, 2004

Point Beach Nuclear Plant Ultrasonic Calibration Record; RC-03-PS-1001-15; dated April 7, 2004

Point Beach Nuclear Plant Ultrasonic Piping Examination Record; RC-03-PS-1001-15; dated April 7, 2004

AF-03-AFW-1002; ISI Isometric Auxiliary Feedwater to Steam Generator B; Revision 1

Point Beach Nuclear Plant Ultrasonic Calibration Record; AF-03-AFW-1002-76; dated April 27, 2004

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FW-16-FW-1002; Primary ISI Isometric PBNP Unit 1 Loop B Feedwater Inside Containment; Revision 4

Point Beach Nuclear Plant Ultrasonic Calibration Record; FW-16-FW-1002-15; dated April 27, 2004

Point Beach Nuclear Plant Ultrasonic Piping Examination Record; FW-16-FW-1002-15; dated April 27, 2004

EB-9-FW-H10; Pipe Hanger Support Detail; Revision 0

Point Beach Nuclear Plant Visual Examination Record; EB-9-FW-H10; dated April 23, 2004

NDE 109; Manual Ultrasonic Examination Using Longitudinal Wave Straight Beam Techniques; Revision 6

NDE 163; Manual Ultrasonic Examination of Ferritic Pressure Vessel Welds Greater Than 2 Inches In Thickness; Revision 10

NDE-172; PDI Generic Procedure For The Ultrasonic Examination Of Ferritic Piping Welds; Revision 7

NDE-173; PDI Generic Procedure For The Ultrasonic Examination Of Austenitic Piping Welds; Revision 6

NDE-350; Magnetic Particle Examination Alternating Current AC Yoke; Revision 24

NDE-451; Visible Dye Penetrant Examination Temperature Applications 45°F to 125°F; Revision 21

NDE-753; Visual Examination (VT-2) Leakage Detection of Nuclear Power Plant Components; Revision 10

Memorandum to G. Sherwood, DE Oakley, R. Turner from W.A. Jenson; ASME Section XI IWA-2240 Demonstration of the Performance Demonstration Initiative Generic Procedure As a Replacement for NDE-163 and NDE-170; dated March 19, 2003

NDE Procedure Qualification NDE-451; Visible Dye Penetrant Examination Temperature Applications 45°F to 125°F; dated March 12, 2002

Documents Associated With Relevant Indications

Indication Disposition Report; Magnetic Particle Examination and Technique Record; Component ID: RPV-HFLANGE-C; Component Description: Head to Flange (AZ 240-360); dated February 15, 2000

Indication Disposition Report; Liquid Penetrant Examination Record; Component ID: RPV; Component Description: CRDM Nozzle #1; dated October 01, 2002

Indication Disposition Report; Magnetic Particle Examination and Technique Record; Component ID: RPV-STUD-44; Component Description: Closure Stud; dated February 15, 2000

Documents Related to Code Pressure Boundary Welding

WO0212615; Cut Weld and Remove Pipe from SI Accumulator Nozzle at 1SI-833C for PT Exam of Nozzle Inner Diameter; dated October 28, 2002

WO0212682; Cut Weld and Remove Pipe from B SI Accumulator Nozzle at 1SI-833B for PT Exam of Nozzle Inner Diameter; dated January 14, 2003

2.P8-GT-SM; Welding Procedure for Austenitic Stainless Steels ASME Group P-8 GTAW- SMAW; Revision 0.

Fillet to Socket Weld Data Sheet; Component: FW-1 and FW-2 T-034B Nozzle; dated October 3, 2002

Documents Related to Code Repairs or Replacements

WO0212615; Cut Weld and Remove Pipe from SI Accumulator Nozzle at 1SI-833C for PT Exam of Nozzle Inner Diameter; dated October 28, 2002

WO0212682; Cut Weld and Remove Pipe from B SI Accumulator Nozzle at 1SI-833B for PT Exam of Nozzle Inner Diameter; dated January 14, 2003

Repair Replacement Form 2002-0095; T-34B; dated September 30, 2002

ASME Section XI Code Reconciliation Checklist; SI System Weld Filler Material; dated September 30, 2002

Visual Weld Examination Record; FW-2; dated October 1, 2002

Visual Weld Examination Record; FW-1; dated October 2, 2002

Liquid Penetrant Examination Record; FW-2; dated October 1, 2002

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ASME Section XI R/R/M Pressure Test Data Sheet; FW-1, FW-2; dated October 13, 2002

WPS 2.P8-GT-SM; Welding Procedure For Austenitic Stainless Steels ASME Group P-8 GTAW-SMAW; Revision 0

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Other Documents

PBNP Indication Disposition Report; IDR No. 02U1-E008; Component No. 1CH-10; Component Description: Core Drilled Hole; dated April 28, 2001

PBNP Indication Disposition Report; IDR No. 01U1-L004; Component No. U1C; Component Description: Unit 1 Containment; dated October 2, 2002

PBNP Fillet/Socket Weld Data Sheet; Equipment No. ISI 00853D; WO No. 0212465; dated October 4, 2002

Drawing No. PBC-309; ISI Classification Drawing: Keyway Sump "A"/Tunnel; dated August 13, 1998

Drawing No. PBC-312; ISI Classification Drawing: Electrical Penetrations; dated September 1, 1998

SEM 7.11.2; ISI Data Sheet Review and Indication Evaluation Guideline; dated March 19, 2004

Documents Related to Steam Generator Tube Inspection Activities

NMC-400-002; Multifrequency ET Testing of Non-Ferromagnetic Steam Generator Tubing; Revision 2

NMC-400-004; Analysis of Rotating Eddy Current Data; Revision 3

NMC-400-003; Analysis of Bobbin Coil Eddy Current Data; Revision 3

NMC-400-007; Eddy Current Site Specific Performance Demonstration; Revision 0

Point Beach Unit 1 Steam Generator Eddy Current Examination Report; dated May 4, 2004

Memorandum from G. Sherwood (NMC) from P. Nelson (WE); dated April 30, 2004

CAP056028; Possible Loose Parts in SG; dated April 24, 2004

Steam Generator Degradation Assessment for Point Beach Unit 1 U1R28; dated April 2004

MRS-TRC-1468; Use of Appendix H Qualified Techniques at Point Beach Unit 1 for the Spring 2004 Steam Generator Inspection; dated April 13, 2004

Westinghouse Electric P-BOB-001; Steam Generator Eddy Current Inspection Examination Technique Specification Sheets; dated April 9, 2004

NP 7.7.17; Requirements for Steam Generator Primary Side Activities; Revision 2

1R11 Licensed Operator Qualifications

Licensed Operator Requalification LOR 04-03, SES 114; Licensed Operator Requalification Training Simulator Scenario 114; dated June 8, 2004, Revision 0

CAP057356; Crew Failure of a LOR Cycle 04-03 Simulator As-Found; dated June 11, 2004

1R12 Maintenance Effectiveness

System Health Report; 125-Volt DC System; April 8, 2004

1R13 Maintenance Risk Assessment and Emergent Work Evaluation

E-1 Report; Work Week Schedule for Week of April 18, 2004

E-1 Report; Work Week Schedule for Week of April 26, 2004

E-1 Report; Work Week Schedule for Week of May 17, 2004

E-1 Report; Work Week Schedule for Week of May 31, 2004

E-1 Report; Work Week Schedule for Week of June 13, 2004

NP 10.3.6; Outage Safety Review and Safety Assessment; Revision 11

NP 10.3.7; On-Line Safety Assessment; Revision 8

CAP055974; P-38A AFW Pump Not Identified on Weekly Safety Monitor Risk Profile; dated April 23, 2004

1R14 Non-Routine Evolutions

CAP056804; Unit 2 Electro-Hydraulic Control Failure During Unit 2 Start-up; dated May 19, 2004

1R15 Operability Evaluations

NP 5.3.7: Operability Determination (OD); Revision 10

NP 5.3.10; Operability Recommendation (OPR); Revision 1

OPR000107 (CAP054534) - Unanalyzed load on Emergency Diesel Generator PBO G-03 and PBO G-04; Revision 0

AOP-22; Unit 1 EDG Load Management; Revision 2

CALC-WE0005-18, Diesel Fuel Oil Consumption

OI 92A; Fuel Oil Ordering, Receipt, Sampling and Offloading; Revision 11

CAP053555; Unit 2 Inadvertent Letdown Isolation; dated February 4, 2004

CAP053560, Application of Temporary Modification Procedure; dated February 5, 2004

CAP053565, Lack of Contingencies for Letdown Problems on U-2; dated February 5, 2004

Instrument and Control Procedure (ICP) 5.21; Pressurizer Level Control; Revision 17

Westinghouse Drawing 883D195, Sheet 18, Logic Diagram - Pressurizer Pressure and Level Control

Westinghouse Drawing 883D195, Sheet 19, Logic Diagram-Pressurizer Heater Control

Foxboro Drawing 10665 CD-13, Sheet 2, Wiring Diagram-Interconnect Reactor Control System Rack 2-PLPP(2C110) Middle

Foxboro Drawing 10665 CD-13, Sheet 3, Wiring Diagram-Interconnect Reactor Control System Rack 2-PLPP(2C110) Bottom

Foxboro Drawing 10665 BD-14, Block Diagram-Instrument-Reactor Control System-Pressurizer Level Control

FP-E-TS-01; NMC Engineering Fleet Procedure - Troubleshooting Process; Revision 0

Routine Maintenance Procedure (RMP) 9201; Control and Documentation for Troubleshooting and Repairs; Revision 0

AOP-1D; Chemical and Volume Control System Malfunction; Revision 2

CAP055332; IN-31 Source Range Pre-Amp Found Defective During the Performance of HCP 04.024; dated April 4, 2004

1ICP 04.024; Nuclear Instrumentation Source Range Channels; Revision 4

Station Logs: April 2, 2004 through April 4, 2004

CAP056170; IT-10 Acceptance Criteria Does Not Ensure Adequate AFW Flow Without Operator Action; dated April 28, 2004

Byron-Jackson Test No. T-30944, Pump Curve for P-38A AFW Pump

Byron-Jackson Test No. T-30945, Pump Curve for P-38B AFW Pump

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ARB 1C20 A 1-5; Unit 1 and 2 Containment Hydrogen System Trouble (White)

ARB 1C20 A 2-5; Unit 1 and 2, Containment Hydrogen System Trouble (Yellow)

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Point Beach Operations Procedure Change Report OPS-2001-00168, ARB 1C20 A 2-5, Unit 1 and 2 Containment Hydrogen System Trouble (Yellow); dated February 3, 2004

1ICP 13.002; Containment Hydrogen Monitor Quarterly Gas Calibration; Revision 4

1R19 Post-Maintenance Testing

NF-NMC-03-190; Point Beach Unit 1, Cycle 29, Region and Fuel Assembly Locations; November 24, 2003

IT 01A; High Head SI Pumps and Valves (Cold Shutdown) Unit 1; Revision 12 with Temporary Change Notice 2004-0418

WO0407597; MS-00228 HX-1A SG Header Drain and Trap Isolation Valve Needs Repack; April 4, 2004

Regulatory Guide 1.141; Containment Isolation Provisions for Fluid Systems; April 1978

CAP057196; Body to Bonnet Steam Leak on 1MS-228 HX-1A SG Header Drain and Trap Isolation; dated June 4, 2004

FSAR Section 5.2; Containment Isolation System; June 2003

FSAR Section 14.2; Steam Generator Tube Rupture; June 2002

Point Beach Nuclear Plant Containment Leakage Rate Testing Program; Basis Document; Revision 6

TS Test 35; Local Leak Test of Containment Purge Valves Unit 1; Revision 24

IT 03; Low Head SI Pumps and Valves (Quarterly) Unit 1, Revision 45 with Temporary Change

PBF-0026e; Temporary Change Review and Approval for IT 03; dated April 29, 2004

PBF-026m; Partial Procedure Performance; IT-03/Low Head SI

CAP056290; 1SI-897B Appears To Be Bound; dated May 1, 2004

Analysis of Return To Service Testing For 1P-10B RHR Pump; dated May 1, 2004

IT 531; Leakage Reduction and Preventive Maintenance Program Test of Containment Sump B Suction Line Mode 5, 6, or Defueled, Unit 1; Revision 14

PBF-0026e; Temporary Change Review and Approval for IT 531; May 3, 2004

<u>1R20</u> <u>Refueling and Outage Activities</u>

WO0407919, Remove and Repair Stuck Bullet

PBF-2114, Return to Service Testing Reviews (WO0407919)

PBF-9812, Categorization and Mitigation of Risk (WO0407919)

PBF-1958, Approval for Hard Hat Exemption (WO0407919)

PBF-9205, High Risk Work Pre-Job Briefing CL (WO0407919)

CAP056617; Evaluate Need to Do Inspection Inside Vessel Prior to Setting Upper Internals; dated May 12, 2004

CL-7A; SI System CL Unit 1; Revision 19

CAP056650; Safety Representative Was Not Present During the Internals Lift; dated May 12, 2004

CAP056649; Missed Management Observation of High Risk Activity; dated May 12, 2004

CAP056651; Management Expectation for Overview of High Risk Work Not Met; dated May 12, 2004

CAP056477; Mode 5 HOLD for Reactor Head Repair; dated May 7, 2004

CAP056490; Z-14 Turbine Hall Crane Coil Failure; dated May 7, 2004

CAP056499; Turbine Building Crane Trolley Brake Transformer Smoking; dated May 7, 2004

CAP056487; Unit 1 SFP Upender Stopped Unexpectedly; dated May 7, 2004

CAP056551; Inconsistencies in Nozzle Dam Protected Equipment Expectations; dated May 9, 2004

CAP056336; Communication Issues Between Engineering, Projects Group, and RP; dated May 2, 2004

CAP056296; Worn Thrust Bearings Being Re-used on 1P-1B-M; dated May 1, 2004

CAP056293; Lift Oil Flow Orifices Not Removed During Previous Mod on RCP Motor; dated May 1, 2004

CAP055691; Reactor Vessel Level Requirements Per GL 88-17; dated April 14, 2004

CAP056387; Clarification on Management Expectations for Performing Observations Required; dated May 4, 2004

CAP055811; Potential Adverse Trend in Operations Inattention to Detail; dated April 17, 2004

CAP055764; Inadequate Staffing of Work Control Center for the U1 Outage; dated April 16, 2004

CAP055738; 1RMP 9007, Precautions and Limitations Not Maintained; dated April 15, 2004

CAP055570; Un-clear Expectation on Management Briefing Before Starting Work; dated April 11, 2004

CAP055365; Potential Unauthorized Modification on U1 Reactor Cavity Manipulator 1Z-16; dated April 5, 2004

CAP055842; Inadequate Response to Shutdown Risk Qualification Issue; dated April 18, 2004

CAP055888; Unit 2 T-34B SI Accumulator Levels Calibrated with Wrong Tolerance M&TE; dated April 20, 2004

CAP055957; Refueling Questions Needing Resolution; dated April 22, 2004

CAP055951; Incore Thermocouple Guide (“Bullet Nose”) Inadvertently Lifted with RX Head; dated April 22, 2004

CAP055979; Extended Period of Time with No Direct RCS Level Indication in Control Room; dated April 23, 2004

CAP055995; Refueling Questions Need Resolution; dated April 23, 2004

CAP056010; P-12A Spent Fuel Pump Breaker Found OFF - Results in Loss of Spent Fuel Cooling; dated April 23, 2004

CAP056015; Spent Fuel Pool Cooling Safety Assessment; dated April 23, 2004

CAP055975; Refueling Cavity Level Raised Without Monitoring RCP Leakoff Collection; dated April 23, 2004

CAP055567; Screening Was Not Obtained Until After Procedure Was Worked; dated April 11, 2004

CAP055876; Z-013 Polar Crane Aux Hoist Fuses Not Per Drawing; dated April 19, 2004

CAP055880; Mis-communication on Return to Service of the Auxiliary Hoist on the Z-13 Crane; dated April 19, 2004

CAP055897; 1Z-013 Auxiliary Hoist Fuse Discrepancy; dated April 20, 2004

CAP055882; Unit 1 Z-13 Polar Crane Phase Firing Thyristors Parts Discrepancy; dated April 20, 2004

CAP055915; U1 Refueling 28 Outage Schedule Conflicts; dated April 21, 2004

CAP056183; SK-37 Lead-in Guide Pulled Up; dated April 28, 2004

CAP056269; Potential Human Performance Error Trap Using RCC [Rod Cluster Control] Change Tool Indication; dated April 30, 2004

CAP056239; 1HX-001A Inspection Port Cover Bolts Torqued in Excess of 1RMP 9032 Requirement; dated April 29, 2004

CAP056236; Control Rod Contacted Top of Fuel Assembly During RCCA [rod Cluster Control Assembly] Changing; dated April 29, 2004

CAP056159; 1B-42, Bolted Short Mod Back in Outage Schedule; dated April 28, 2004

CAP055691; Reactor Vessel Level Requirements Per GL 88-17; dated April 14, 2004

1R22 Surveillance Testing

IT-9A; Cold Start of Turbine-Driven Auxiliary Feed Pump and Valve Test, Unit 2, Revision 34

WO0408743; MS-02019-O, HX-1B SG Header P-29 AFP [Auxiliary Feedwater Pump] Steam Supply MOV [Motor-Operated Valve] Operator; dated June 1, 2004

RMP 9376-2; Limitorque MOV Static/DP [Differential Pressure] Testing for Gate and Globe Valves; Revision 10

WO0408741; MS-02020-O, HX-1A SG Header P-29 AFP Steam Supply MOV Operator; dated May 31, 2004

RMP 9376-7; MOV Troubleshooting Guide; Revision 2

CAP057117; Steam Supply Valves to 2P-29 AFW Pump Failures During IT-09A; dated May 31, 2004

ORT 3A; SI Actuation With Loss of Engineered Safeguards AC (Train A) Unit 1; Revision 37

CAP030028; Quarterly Vibration Readings on the RHR Pumps; dated April 30, 2003

IT 03; Low Head SI Pumps and Valves (Quarterly) Unit 1; dated February 5, 2004

IT 04; Low Head SI Pumps and Valves (Quarterly) Unit 2; dated September 8, 2003

Trend Data IT-3 Series (RHR); 1P-10A RHR Pump; dated March 30, 2004

Trend Data IT-3 Series (RHR); 1P-10B RHR Pump; dated March 30, 2004

Trend Data IT-3 Series (RHR); 2P-10A RHR Pump; dated March 30, 2004

Trend Data IT-3 Series (RHR); 2P-10B RHR Pump; dated March 30, 2004

IT 760; Flow Test of High Head SI Check Valves (Refueling) Unit 1; dated September 12, 2002

PBF-0026e; Temporary Change 2004-0321; dated April 21, 2004

PBF-0026; Temporary Change Affected Manual Location (TC#2004-0321)

PBF-1515b; 10 CFR 50.59/72.48 Pre-Screening Review, Temp Procedure Change to IT-760 (TC#2004-0321); dated April 21, 2004

PBF-0026e; Temporary Change 2004-0322; dated April 21, 2004

PBF-0026h; Temporary Change Affected Manual Location (TC#2004-0322)

PBF-1515b, 10 CFR 50.59/72.48 Pre-Screening Review; Temp Procedure Change to IT-760 (TC#2004-0322); dated April 21, 2004

PBF-1515c, 10CFR 50.59/72.48 Screening (New Rule) SCR 2003-0329; Steam Generator Nozzle Dams; dated September 22, 2003

RP 1A; Preparation for Refueling; dated April 22, 2004

IT 03; Low Head SI Pumps and Valves (Quarterly) Unit 1; Revision 46

1R23 Temporary Plant Modifications

TM 04-001; Temporary Replacement Of Unit 1 Purge Supply/Return Valves; Revision 0

OI 58; Leak Testing of Containment Isolation Valves - Unit 1 and 2 General Instructions and Information; Revision 22

TS Bases 3.9.3 Change; TS Basis B 3.9.3 - Containment Penetrations Change; dated June 2, 2004

TM 04-005; Auxiliary Feed Tunnel Seismic Event Annunciation; Revision 0

1EP4 Emergency Action Level and Emergency Plan Changes

Point Beach Nuclear Plant Emergency Plan; Section 2; Revision 40

Point Beach Nuclear Plant Emergency Plan; Section 7; Revision 46

1EP6 Drill Evaluation

LOR 04-03 Scenario SES 114; Licensed Operator Requalification Training Scenario; Revision 0, dated May 25, 2004

LOR TRPR 33.0; Operations Crew Failure PRC Minutes, dated June 10, 2004

TI 8.0, Attachment 2; Conduct of Simulator Training and Simulator Evaluation; Revision 6

2OS1 Access Control to Radiologically Significant Areas

CAP 055366; Worker Received Electronic Dosimeter Dose Alarm; dated April 5, 2004

CAP 055587; S/G Nozzle Dam Installation Dose Exceeded Estimate; dated April 11, 2004

CAP 055595; Air Supply to Bubble Hoods Not Within Procedure Limits; dated April 12, 2004

CAP 055951; Incore Thermocouple Guide ("Bullet Nose") Inadvertently Lifted with Reactor Head; dated April 22, 2004

CAP 055986; Evaluate Use of RP Greeter at Containment Hatches During Outage Periods; dated April 23, 2004 [NRC-Identified Issue]

HP 3.2; Radiological Labeling, Posting, and Barricading Requirements; Revision 39

HPIP 4.58; Issuance of Respiratory Equipment; Revision 13

HPIP 3.52; Airborne Radioactivity Surveys; Revision 30

PCE No. 04-02-018; Personnel Contamination Event (PCE) Report; dated April 8, 2004

PCE No. 04-02-019; Personnel Contamination Event (PCE) Report; dated April 9, 2004

PCE No. 04-02-020; Personnel Contamination Event (PCE) Report; dated April 8, 2004

RCE 253/CAP055527; Industrial Safety Issues and Poor Work Practices During Nozzle Dam Installation; dated May 22, 2004

RWP No. 04-104; RP Coverage; Revision 0

RWP No. 04-113; Reactor Head Lift; Revision 0

RWP No. 04-122; Reactor Coolant Pump Maintenance; Revision 0

RWP No. 04-133; BMI Inspection; Revision 0

RWP No. 04-141; Nozzle Dam Install/Remove; Revision 0

RWP No. 04-142; Steam Generator Eddy Current Testing; Revision 1

RWP No. 04-171; NRC Walkdowns for U1R28; Revision 0

RWP No. 04-182; Replace Cono-Seal Bullet; Revision 0

2OS2 ALARA Planning And Controls

ALARA Review No. 2004-0012; Level 3 Pre-Job ALARA Review for BMI Inspection (RWP No. 04-133); dated April 6, 2004

ALARA Review No. 2004-0017; Level 3 Pre-Job and In-Progress ALARA Reviews for Nozzle Dam Install/Remove (RWP No. 04-141); dated April 2 and 11, 2004

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ALARA Review No. 2004-0027; Level 3 Pre-Job ALARA Review for Replace Cono-Seal Bullet (RWP No. 04-182); dated April 22, 2004

JIT Briefing Activity MM-8480D3; Just In Time Briefing for Reactor Vessel Head Lift; dated April 21, 2004

HPIP 4.40; TEDE ALARA Evaluation; Revision 0 (February 6, 2002)

NP 4.2.1; ALARA Program; Revision 11 (November 19, 2003)

Point Beach Nuclear Plant U1R28 Estimated RWP Dose Spreadsheet; dated April 6, 2004

TEDE ALARA Evaluation for RWP 04-141; dated April 3, 2004

TEDE ALARA Evaluation for RWP 04-182; dated April 22, 2004

4OA1 Performance Indicator Verification

NP 5.2.16; NRC Performance Indicators Attachment C for Unplanned Scrams, Unit 1 PI Data Calculation, Review and Approval; Revision 7, April 23, 2004

NP 5.2.16; NRC Performance Indicators Attachment C for Unplanned Scrams, Unit 2 PI Data Calculation, Review and Approval; Revision 7, April 23, 2004

NP 5.2.16; NRC Performance Indicators Attachment C for Scrams With Loss of Heat Removal, Unit 1 PI Data Calculation, Review and Approval; Revision 7, April 23, 2004

NP 5.2.16; NRC Performance Indicators Attachment C for Scrams With Loss of Heat Removal, Unit 2 PI Data Calculation, Review and Approval; Revision 7, April 23, 2004

4OA2 Identification and Resolution of Problems - Inservice Inspection

Corrective Action Documents

CAP047990; OE 14934 Problems with Ultrasonic Testing Caused Unnecessary Pipe Replacement; dated August 21, 2003

CAP054136; Unit 2 S/G Tube Leakage Exceeded 5 gpd; dated February 23, 2004

CAP053177; Increased Fluoride Contamination in the Unit 1 S/Gs; dated January 25, 2004

CAP033575; OE 16308 Incorrect Diameter Probe Used During Eddy Current Inspection; dated June 16, 2003

CAP029936; Service Water Intrusion into “A” and “B” S/Gs for Unit 1; dated October 26, 2002

CAP003372; NSAL-02-13 Fatigue Life of CE [combustion Engineering] Steam Generator Primary Manway Studs; dated August 20, 2003

CAP032045; New AFW Restricting Orifices May Not Meet Section XI R/R [Repair/Replacement] Requirements; dated April 6, 2003

CAP051046; SW Pipe Wall Thinning Noted During Execution of U2R26 WO 9905610; dated October 14, 2003

CAP032290; Inservice Inspection Limited Examinations; dated April 17, 2003

CAP051206; Small Wires Found in the Secondary Side on the “A” Steam Generator; dated October 18, 2003

CAP051407; Small Wires Found in the Secondary Side on the “B” Steam Generator; dated October 24, 2003

CAP029413; Accumulator Nozzle Have Unidentified Indications on the Inside Surface; dated September 19, 2002

CAP010698; Accumulator Nozzles Have Unidentified Indications on the Inside Surface; dated September 21, 2002

OTH026613; Accumulator Nozzles Have Unidentified Indications on the Inside Surface; dated October 07, 2002

OTH026615; Accumulator Nozzles Have Unidentified Indications on the Inside Surface; dated October 07, 2002

OTH026616; Accumulator Nozzles Have Unidentified Indications on the Inside Surface; dated October 07, 2002

CE012362; Framatome NRC 6028873 - Lack of UT Coverage During U1R27 RPV Inspection; dated September 18, 2003

CA053202; Framatome NRC 6028873 - Lack of UT Coverage During U1R27 RPV Inspection; dated October 15, 2003

CAP022754; Liner Plate Degradation; dated April 25, 2002

CAP012575; Liner Plate Degradation-U1R26 Restart Issue; dated April 13, 2001

CAP012576; Liner Plate Degradation; dated April 13, 2001

Corrective Action Reports Initiated as a Result of NRC Inspection

CAP055529; NIS-1 Report Contains Information That Could Be Misunderstood; dated April 09, 2004

CAP055517; Repair/Replacement Documentation May Have Incomplete Information; dated April 09, 2004

CAP055652; Wrong Size of Weld Filler Metal Used; dated April 13, 2004

CAP055664; Procedure NDE-750 Does Not Require Recording Boric Acid on Stainless Steel Bolts; dated April 13, 2004

CAP055678; Feedback Regarding NDE From NRC Exit on April 9, 2004; dated April 14, 2004

CAP056011; Tracking Mechanism for ISI Relief Requests Not Clear; dated April 23, 2004

OTH012761; Calculate New RPV Head Temperatures - Post RPV Head Replacement; dated April 26, 2004

4OA2 Identification and Resolution of Problems - Resident Inspector Samples

CAP052757; 2P-2B Charging Pump Tripped; dated January 12, 2004

CAP052764; 2P-2B tripped while opening door on 2B-03; dated January 12, 2004

CAP052838; Seismic Question of B03 and B04 Buses; dated January 15, 2004

Maintenance Rule Evaluation MRE000152: Maintenance Rule Evaluation, 2P-2B Trip; dated January 12, 2004

CE012929; 2P-2B Trip; dated January 12, 2004

WO0400401; Door for Relay Cubicle is Sprung (Ref CAP052764)

WO0400534; Document Maintenance Rule Functional Failure of 2P-2B Charging Pump

NP 7.7.2; Seismic Qualification of Equipment; Revision 2

NP 13.1.1; Self-Assessment Program; Revision 10

CAP056602; Ineffective CA on 1RH-713A/B, Evidence During IT-530C; dated May 11, 2004

WEST110E018 Sheet 1; Auxiliary Coolant System Unit 1; Revision 57

DBD-10; RHR System, Section 3.7; Revision 1

CAP056580; Unexpected Cavity Level Decrease During IT-530C; dated May 11, 2004

NMC Incident Response Team For Issues Encountered During Unit 2 Trip Due to Diver Trapped in Intake Structure at PBNP; dated May 17, 2004

CAP056785; CA Designated as CATPR [Corrective Action To Prevent Recurrence] in RCE 00-093 Not Implemented; dated May 18, 2004

CAP056774; Wrong Cubicle Opened, WO 0407727; dated May 18, 2004

CAP056776; 1X-04 Annunciator Alarm Activated by D52A Selector Switch Operation, dated May 17, 2004

Point Beach Nuclear Plant Corrective Action Program Report, 4th Quarter 2003

Point Beach Nuclear Plant Corrective Action Program Report, 1st Quarter 2004

Nuclear Plant Memorandum NPM 2004-00344; First Quarter Human Performance Analysis; dated April 30, 2004

CAP057010; 1st Quarter Human Performance Data Analysis; dated May 26, 2004

CAP057705; 2004 CAP Self-Assessment - Minor Issues; dated July 1, 2004

CA054949; Mispositioning Adverse Trend Identified - Wrong Unit, Wrong Train, Wrong Device; dated January 13, 2004

4OA3 Event Follow-up

LER 301/2004-001-00; SI System Accumulator Operated With Fluid Level Out Of Specification High; May 21, 2004

CAP055204; Troubleshooting Reveals 2T34A SI Accumulator Level Out of Specification High; dated March 30, 2004

RCE000251; Root Cause Evaluation; 2T-34A SI Accumulator Level Instruments Returned to Service Without Proper Post Maintenance Testing; Revision 0

CAP055415; Organization Response to Unit 2 SI Accumulator Level Transmitter Issues; dated April 7, 2004

CAP056175; Nuclear Safety Culture Assessment Required; April 28, 2004

CAP056363; Missed TSAC Entry Following Denergizing of 1Y-04; dated May 4, 2004

4OA5.1 Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles (TI 2515/150)

Nondestructive Examination Reports

Point Beach Unit 1 (U1R28) - Extent of UT Coverage in RVHP Nozzle Material; dated May 6, 2004

Point Beach Nuclear Power Plant Liquid Penetrant Examination Record; Nozzle 26; dated April 29, 2004

Point Beach Nuclear Power Plant Liquid Penetrant Examination Record; Nozzle 26; dated May 2, 2004

Point Beach Nuclear Power Plant Liquid Penetrant Examination Record; Nozzle 26; dated May 5, 2004

Videotaped of Dye Penetrant Examinations of Nozzle 26; Performed April 29, 2004, April 30, 2004, May 2, 2004, and May 5, 2004

Point Beach Nuclear Power Plant Visual Examination Record; RPV Closure Head; dated April 26, 2004

Point Beach Nuclear Power Plant Visual Examination Record; RPV Closure Head; dated April 27, 2004

Point Beach Nuclear Power Plant Visual Examination Record; RPV Closure Head; dated May 1, 2004

Point Beach Nuclear Power Plant Remote Visual Examination Record; RPV Closure Head; dated May 23, 2004

Point Beach Nuclear Power Plant Visual Examination Record; RPV Closure Head; dated May 6, 2004

Point Beach Nuclear Power Plant Ultrasonic Calibration Record; Penetrations 32 and 33; dated May 14, 2004

Videotaped Upper Head Examination and Cleaning from April 26, 2004 through May 6, 2004

Ultrasonic Calibration Data Sheets; Penetration No. 26 J-Groove Weld After Machining 0, 45 Degree, and OD Creeping Wave Scans; dated May 12, 2004

51-5045099-00; Point Beach Unit 1 (U1R28) RVH Nozzle UT Inspection Final Report; Draft; dated May 26, 2004

Other Documents

Westinghouse Letter Report LTR-RCDA-0377; Revision 2

C11470; Reactor Vessel Head Effective Degradation Year (EDY); dated May 29, 2003

EPRI MRP-89; Materials Reliability Program Demonstrations of Vendor Equipment and Procedures for the Inspection of Control Rod Drive Mechanism Head Penetrations; dated September 2003

WCAP-15950; Structural Integrity Evaluation of Reactor Vessel Upper Head Penetration to Support Continued Operation of Point Beach Units 1 and 2; dated September 2002

PWR Materials Reliability Program Response to NRC Bulletin 2001-01 (MPR-48); EPRI 1006284; dated August 2001

Calculation Cover Sheet and Review Report; Reactor Vessel Head Effective Degradation; Calc # C11470; dated May 29, 2003

Letter from B. Rassler (EPRI) to B. Jenson (Nuclear Management Company); Blind Demonstration Testing of UT Procedure; dated May 3, 2004

54-ISI-30-01; Written Practice for the Qualification and Certification of NDE Personnel; dated August 18, 2004

Framatome ANP Certificate of Personnel Qualification for:

- Jonathan D. Buttram, UT Level III; dated February 5, 2004;
- Jason D. Breza, UT Level II; dated January 29, 2004;
- Michael W. Key, UT Level III; dated January 29, 2004;
- Kent Gebetsberger, UT; dated September 14, 2002;
- Chuck Martin, UT Level II; dated September 14, 2002;
- John Touhalisky, UT Level II; dated September 14, 2002; and
- Robert Kellerhall, UT Level II; dated September 14, 2002.

NMC Record of Certificate of NDE Personnel as UT Level III for William Jensen; dated August 19, 2003

1-PT-RCS-1; Reactor Coolant System Pressure Test - Inside/Outside Containment Unit 1; dated October 15, 2002

1-PT-RCS-1; Reactor Coolant System Pressure Test - Inside/Outside Containment Unit 1 Appendix B; dated October 13, 2002

SEM 7.11.5; RCS Leak Test for Unit 1; dated April 13, 2001

WO9923859; Visual Examination Leak Test Record Data Sheets (13 pages); dated May 9, 2001

Boric Acid Walkdown Data Sheets Refueling Outage: U1R27; dated September 15, 2002

Organizational Assessment Audit Plan and Checklist: First Quarter 2001 Engineering Audit; Scope: Repair and Replacement Modification Activities Relating to ASME Section XI, Inservice Testing per ASME Section XI; Document #: A-P-01-03; dated January 15, 2001

Record of Certification of NDE Personnel; William Jensen; Visual Level III; dated August 13, 2003

Record of Certification of NDE Personnel; Patric Turner; Visual Level II; dated August 12, 2003

Weld Control Records; Layers 1 through 14; dated May 12 and 13, 2004
Drawing 5019702; Point Beach Unit 1 CRDM [Control Rod Drive Mechanism] Nozzle ID [Inner Diameter] Temper Bead Weld Repair; Revision 3

Quality Assurance Data Package No. 23-5044625-00; Welding Filler Material For NMC, Point Beach Unit 1 Reactor Vessel Head Repair; dated May 7, 2004

Process Traveler; Ambient ID Temper Bead Repair For CRDM Nozzles; dated May 7, 2004

Repair/Replacement Form No. 2004-03; Repair Nozzle 26; dated May 11, 2004

Weld Procedure Specification 55-WP3/43/F43TBSCA301; Revision 1

Procedure Qualification Record 55- PQ7164-03; dated May 23, 2003

Procedure Qualification Record 55- PQ7183-03; dated May 8, 2004

WCAP 14929; Probabilistic Evaluation of Reactor Vessel Closure Head Penetration Integrity for Point Beach Units 1 and 2; Revision 0

Point Beach U1R27 Reactor Vessel Head CRDM Nozzle Ultrasonic Examination Report; dated October 5, 2002

Memorandum to File; Point Beach Nuclear Plant Vessel Closure Head Temperature; dated April 22, 2004

MRP-89; Materials Reliability Program Demonstrations of Vendor Equipment and Procedures for the Inspection of Control Rod Drive Mechanism Head Penetrations; dated September 2003

54-5016639-00; Framatome ANP Reactor Vessel Head Penetration Leak Path Qualification Report; dated February 6, 2002

54-5040736-00; Framatome ANP Demonstration of CRDM Leak Path Detection Technique; dated February 26, 2004

Letter from A. Johnson (WE) to USNRC; GL 97-01 120 Day Response Point Beach Nuclear Plant, Units 1 and 2; dated July 30, 1997

Letter from A. J Cayia (NMC) to USNRC; Supplemental Response to NRC Bulletins 2001-01, 2002-01, and 2002-02 for Reactor Vessel Head and Head Penetration Nozzle Inspection Findings; dated November 24, 2003

CA053202; Framatome NCR [Non-Conformance Report] 6028873-Lack of UT Coverage During U1R27 RPV Inspection; dated October 15, 2003

CE012362; Framatome NCR 6028873-Lack of UT Coverage During U1R27 RPV Inspection; dated September 18, 2003

Memorandum; Obstructed Area of Unit 1 Reactor Vessel Dome; dated May 24, 2004

Procedures

NDE-757; Visual Examination For Leakage of Reactor Pressure Vessel Penetrations; Revision 3

NDE-451; Visible Dye Penetrant Examination Temperature Applications 45°F to 125°F; Revision 21

54-ISI-100-11; Remote Ultrasonic Examination of Reactor Head Penetrations; Revisions 9 through 11

54-ISI-137-03; Remote Ultrasonic Examination of Reactor Vessel Head Vent Line Penetrations; Revision 3

54-PQ-137-01; Remote Ultrasonic Examination of Reactor Vessel Head Vent Line Penetrations; dated February 22, 2002

54-PQ-137-01; Remote Ultrasonic Examination of Reactor Vessel Head Vent Line Penetrations; dated September 20, 2002

54-PQ-137-01; Remote Ultrasonic Examination of Reactor Vessel Head Vent Line Penetrations; dated November 21, 2002

1-PT-RCS-1; Reactor Coolant System (RCS) Pressure Test- Inside/Outside Containment Unit 1; Revision 1

NP 7.4.14; Boric Acid Leakage and Corrosion Monitoring; Revision 0

Boric Acid Leakage and Corrosion Monitoring Program; Revision 0

NDE-141; Manual Ultrasonic Examination of Reactor Head Penetrations; Revision 0

4OA5.2 Reactor Pressure Vessel Lower Head Penetration Nozzles (TI 2515/152)

Drawings

TP-3609-4; Section Thru Bottom of Reactor Vessel; Revision 0

RT-49006-RI; RVCH Insulation System General Arrangement Drawing; Revision 0

West 685J441, Sheets A, B, C, and D; NIS Bottom Mounted Instrumentation Point Beach NP; Revision 9

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Point Beach Visual Examination Record; Reactor Pressure Vessel BMI Tubes; dated April 6, 2004

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NDE-757; Visual Examination For Leakage of Reactor Pressure Vessel Penetrations; Revision 3

NDE-3; Written Practice For Qualification And Certification For NDE Personnel; Revision 28

2-NDES-001; Nondestructive Examination Personnel Qualification and Certification; Revision 2

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Point Beach Nuclear Plant Visual Examination Record; Reactor Pressure Vessel BMI Tubes; dated April 6, 2004

Record of Certification NDE Personnel; William Jensen; dated August 19, 1983

IHI Southwest Technologies, INC. Statement of NDE Certification; Victor Morton; dated January 5, 2004

4OA5.4 Reactor Containment Sump Blockage Point Beach Units 1 & 2 (TI 2515/153)

CAP05785; Vendor Program Applicability Problems Deleted Monitored Parameters for Sump Blockage; dated July 9, 2004

CAP050529; Problems With Vendor Program Delayed Preparations for EOP Issuance; dated July 9, 2004

EOP -1 Unit 1; Loss of Reactor or Secondary Coolant; Revision 35

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4OA5.6 Offsite Power System Operational Readiness (TI 2515/156)

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DBD-20; 345 KVAC [Kilovolt Alternating Current] System; Revision 2

NP 2.1.5; Electrical Communications, Switchyard Access and Work Planning; Revision 3

NP 2.1.8; Protected Equipment; Revision 0

NP 10.3.6; Outage Safety Review and Safety Assessment; Revision 11

NP 10.3.7; On-Line Safety Assessment; Revision 8

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CAP050179; Industry OE - Callaway - Inoperability of Both Offsite Power Sources; dated September 15, 2003

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OP 2A, Normal Power Operation, Revision 50

LIST OF ACRONYMS USED

ACE	Apparent Cause Evaluation
ADAMS	Agency Wide Access Management System
AFW	Auxiliary Feedwater
ALARA	As-Low-As-Is-Reasonably-Achievable
AOP	Abnormal Operating Procedure
ARB	Alarm Response Book
ASME	American Society of Mechanical Engineers
ATC	American Transmission Company
BMI	Bottom Mounted Instrument
CA	Corrective Action
CAP	Corrective Action Program Document
CCW	Component Cooling Water
CE	Condition Evaluation
CFR	Code of Federal Regulations
CL	Checklist
COLR	Core Operating Limits Report
CRDM	Control Rod Drive Mechanism
CSP	Critical Safety Procedure
CW	Circulating Water
DBD	Design Basis Document
ECA	Emergency Contingency Action
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EDM	Electric Discharge Machined
EDY	Effective Degradation Years
EOP	Emergency Operating Procedure
EPRI	Electric Power Research Institute
ET	Eddy Current Test
FHAR	Fire Hazard Analysis Report
FPER	Fire Protection Evaluation Report
FSAR	Final Safety Analysis Report
GL	Generic Letter
HPIP	Health Physics Implementing Procedure
HX	Heat Exchanger
ICP	Instrument and Control Procedure
IMC	Inspection Manual Chapter
IP	Inspection Procedure
ISI	Inservice Inspection
IT	Inservice Test
KV	Kilo-Volt
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
LOR	Licensed Operator Requalification
MIC	Microbiologically Induced Corrosion
MOV	Motor-Operated Valve

NCV	Non-Cited Violation
NDE	Nondestructive Examination
NIOSH	National Institute for Occupational Safety and Health
NMC	Nuclear Management Company
NP	Nuclear Plant Procedures Manual
NRC	Nuclear Regulatory Commission
No.	Number
OCC	Outage Control Center
ODSCC	Outside Diameter Stress Corrosion Cracking
OE	Operating Events/Experience
OI	Operating Instruction
OM	Operations Manual
OP	Operating Procedure
OPR	Operability Recommendation
OS	Occupational Radiation Safety
OTH	Other (Corrective Action Program Document)
OWA	Operator Workaround
PBF	Point Beach Form
PBNP	Point Beach Nuclear Plant
PC	Periodic Check
PCE	Personnel Contamination Event
PI	Performance Indicator
PMT	Post-Maintenance Testing
ppm	Parts Per Million
psig	pounds per square inch gauge
PT	Dye Penetrant Test
PWSCC	Primary Water Stress Crack Corrosion
PWR	Pressurized Water Reactor
RCE	Root Cause Evaluation
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RMP	Routine Maintenance Procedure
RNO	Response Not Obtained
RP	Radiation Protection
RPV	Reactor Pressure Vessel
RWP	Radiation Work Permit
SDP	Significance Determination Process
SEP	Shutdown Emergency Procedure
SFP	Spent Fuel Pool
SG	Steam Generator
SI	Safety Injection
SR	Surveillance Requirement
SW	Service Water
TEDE	Total Effective Dose Equivalent
TI	Temporary Instruction
TM	Temporary Modification
TOFD	Time Of Flight Diffraction
TSB	Technical Support Building

TS	Technical Specification
TSAC	Technical Specification Action Condition
U1R28	Unit 1 Refueling Outage 28
UHS	Ultimate Heat Sink
URI	Unresolved item
UT	Ultrasonic Test
VHP	Vessel Head Penetration
WE	Wisconsin Electric
WO	Work Order
WPS	Weld Procedure Specification