February 13, 2008

Mr. James McCarthy
Site Vice President
FPL Energy Point Beach, LLC
6610 Nuclear Road
Two Rivers, WI 54241

SUBJECT: POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2, NRC INTEGRATED INSPECTION REPORT 05000266/2007005 AND 05000301/2007005

Dear Mr. McCarthy:

On December 31, 2007, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Point Beach Nuclear Plant, Units 1 and 2. The enclosed inspection report documents the inspection results, which were discussed on January 10, 2008, with you and members of your staff.

The inspection examined activities conducted under your license as they relate to safety and 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 your personnel.

Based on the results of this inspection, seven NRC-identified and self-revealed findings of very low safety significance (Green) were identified. Five of these findings were determined to involve violations of NRC requirements. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these findings as Non-Cited Violations (NCVs), consistent with Section VI.A.1 of the NRC Enforcement Policy. If you contest any 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.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) 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), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Michael A. Kunowski, Chief
Branch 5
Division of Reactor Projects

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

Enclosure: Inspection Report 05000266/2007005; 05000301/2007005
w/Attachment: Supplemental Information

cc w/encl: M. Nazar, Senior Vice President and Nuclear
Chief Operating Officer
J. Stall, Senior Vice President and
Chief Nuclear Officer
R. Kundalkar, Vice President, Nuclear Technical Services
Licensing Manager, Point Beach Nuclear Plant
M. Ross, Managing Attorney
A. Fernandez, Senior Attorney
K. Duveneck, Town Chairman
Town of Two Creeks
Chairperson
Public Service Commission of Wisconsin
J. Kitsembel, Electric Division
Public Service Commission of Wisconsin
State Liaison Officer

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Letter to J. McCarthy from M. Kunowski dated February 13, 2008.

SUBJECT: POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2, NRC INTEGRATED INSPECTION REPORT 05000266/2007005 AND 05000301/2007005

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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:	05000266/2007005; 05000301/2007005
Licensee:	FPL Energy Point Beach, LLC
Facility:	Point Beach Nuclear Plant, Units 1 and 2
Location:	Two Rivers, Wisconsin
Dates:	October 1, 2007, through December 31, 2007
Inspectors:	R. Krsek, Senior Resident Inspector R. Ruiz, Resident Inspector S. Burton, Senior Resident Inspector, Kewaunee P. Higgins, Resident Inspector, Kewaunee W. Slawinski, Senior Health Physicist C. Zoia, Operations Engineer N. Valos, Senior Operations Engineer K. Walton, Operations Engineer R. Winter, Reactor Engineer M. Jones, Reactor Engineer
Approved by:	Michael Kunowski, Chief Branch 5 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000266/2007005, 05000301/20070005; 10/01/2007-12/31/2007; Point Beach Nuclear Plant, Units 1 & 2; Adverse Weather Protection; Operability Evaluations; Followup of Events; Other Activities.

This report covers a three-month period of inspections by resident inspectors and regional specialists. Seven Green findings were identified. Five of the findings which were identified had associated Non-Cited Violations (NCVs). 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 4, dated December 2006.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. The inspectors identified a finding of very low safety significance with no associated violation of regulatory requirements for the licensee's failure to control loose materials in the protected area. Specifically, the inspectors identified materials that were classified as tornado hazards per station procedure PC 99 near the Unit 1 and Unit 2 main and auxiliary transformers and the switchyard boundary. Once notified, the licensee entered the issue into its corrective action program and removed the materials. In addition, a procedure change request was initiated to incorporate tornado hazard walkdowns into the abnormal operating procedure for severe weather response.

  The finding is more than minor because if left uncorrected, the loose items would become a more significant safety concern. The finding is of very low safety significance (Green) because it did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available. Additionally, the inspectors determined that the finding had a cross-cutting aspect in the area of problem identification and resolution in that the licensee failed to take appropriate corrective actions to address safety issues and adverse trends in a timely manner, commensurate with their safety significance and complexity (P.1(d)). (Section 1R01.1)

Cornerstone: Mitigating Systems

- Green. A self-revealed finding with no associated violation of regulatory requirements was identified for an inadequate operability evaluation performed in June 2007 for service water pump P-32C. Specifically, the pump failed its inservice test (IST) on high vibrations after approximately six hours of operation, but the operability evaluation had concluded the pump vibrations would not reach the out-of-service limit until after 120 hours of continuous operation. Contributing to the unanticipated early failure was the use of non-conservative decision-making and the use of a non-conservative assumption in the pump's vibration prediction model. The licensee entered this issue into its corrective action program and P-32C was subsequently repaired and returned to service.

The finding is more than minor because it could reasonably be viewed as a precursor to a significant event. The finding is of very low safety significance (Green) because there was no design deficiency, no actual loss of safety function, no single train loss of safety function for greater than the Technical Specification (TS) allowed outage time, and no risk due to external events. Additionally, the inspectors determined that the finding had a cross-cutting aspect in the area of human performance. Specifically, the licensee failed to use conservative assumptions in decision-making affecting operability of safety-related equipment (H.1(b)). (Section 1R15.1)

- Green. The inspectors identified a finding of very low safety significance (Green) and an associated Non-Cited Violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," for the failure to adequately assess operability of the Unit 2 2P-29 turbine-driven auxiliary feedwater (TDAFW) pump. The licensee failed to implement procedural requirements regarding the immediate assessment of operability on September 24 and September 27, 2007, for the increased water ingress into the turbine outboard bearing housing for the pump following maintenance activities. The licensee took corrective actions, which included performing an operability evaluation on November 1 when the next scheduled test again revealed higher than normal levels of water in the bearing oil. However, the inspectors continued to identify, in the subsequent revisions to the operability determination, that the licensee failed to utilize all the data available to assess pump operability. At the end of the inspection period, the licensee continued to evaluate the causes and corrective actions to address this finding.

  The finding is more than minor because, if left uncorrected, the failure to properly assess operability would result in the TDAFW pump being degraded, and possibly inoperable for more than the allowed outage time in accordance with TSs with no action being taken. The finding is of very low safety significance (Green) because the inadequate operability determination did not result in exceeding the allowed outage time of TSs before action was taken. Additionally, the inspectors determined that the finding had a cross-cutting aspect in the area of human performance. Specifically, the licensee failed to use conservative assumptions in decision-making affecting operability of safety-related equipment (H.1(b)). (Section 1R15.2)

- Green. A self-revealed finding and an associated Non-Cited Violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," were identified for the failure to have adequate procedures to allow operators to properly set the thermostat of the Unit 2 refueling water storage tank (RWST) heaters and to ensure the RWST was recirculated frequently enough for the temperature indicator to accurately measure bulk temperature. On September 18, 2007, the Unit 2 RWST was found to be at 105 °F. This temperature exceeded the TS-maximum allowable limit of 100 °F (97 °F parametric) and could not be restored to acceptable limits before the eight-hour TS action statement expired. As a result, a shutdown of Unit 2 was commenced. At 20 percent power, a return to full power began after the RWST temperature was restored to within acceptable limits. It was later identified that the undesired heat-up was caused by the incorrect setting of the controlling thermostat for the RWST heaters.

The finding is more than minor because it is associated with the procedure quality and human performance attributes of the Mitigating Systems Cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). The finding is of very low safety significance (Green) because the elevated temperature of the RWST and subsequent shutdown sequence did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available. Additionally, the inspectors determined that the finding had a cross-cutting aspect in the area of human performance. Specifically, human error prevention techniques were not utilized prior to and during the thermostat setting task and personnel proceeded in the face of uncertainty and unexpected circumstances (H.4(a)). (Section 4OA3.1)

- Green. The inspectors identified a finding of very low safety significance and an associated Non-Cited Violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," for the licensee's failure to conduct adequate post-maintenance testing of the Unit 1 1P-29 turbine-driven auxiliary feedwater (TDAFW) pump following a ten-year overhaul of the turbine in May 2007. Specifically, the ten-year overhaul maintenance included bearing replacement, but the TDAFW pump was not run long enough during testing for bearing temperature to stabilize. The appropriate post-maintenance test would have detected that the bearing temperatures were rising and required evaluation prior to declaring the TDAFW pump operable. The licensee entered the issue into its corrective action program and took immediate corrective actions. Additionally, the licensee initiated changes to the inadequate procedures.

  The finding is more than minor because, if left uncorrected, the issue would have become a more significant safety concern. The inspectors determined this finding was not a design qualification deficiency resulting in a loss of function per NRC Generic Letter 91-18, did not represent an actual loss of safety function of a system or train of equipment, and was not potentially risk-significant due to a seismic, fire, flooding, or severe weather initiating event. Therefore, the finding is considered to be of very low safety significance (Green). Additionally, the inspectors determined that the finding had a cross-cutting aspect in the area of human performance. Specifically, the licensee failed to ensure that procedures were adequate and accurate to assure nuclear safety (H.2(c)). (Section 4OA5.1)

- Green. The inspectors identified a finding of very low safety significance and an associated Non-Cited Violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," for the failure to implement prompt corrective actions for the degraded oil conditions initially identified with the Unit 2 2P-29 turbine-driven auxiliary feedwater (TDAFW) pump on September 24, 2007, following maintenance. Following an additional oil sample with favorable results, the licensee incorrectly concluded, due to confirmational biases, that the high water content of the first oil sample was an expected condition. The licensee wrote a condition report, but it was closed with no actions taken. In November 2007, the licensee identified that a significant degraded oil condition existed with the pump. The licensee entered the issue into its corrective action program and took immediate corrective actions, including rebuilding the pump turbine. The licensee continued to evaluate the causes and corrective actions to address this finding at the end of the inspection period.

The finding is more than minor because it could reasonably be viewed as a precursor to a significant event. Specifically, the failure to correct the cause of the oil degradation in a timely manner in September 2007 could have resulted in the failure of the 2P-29 TDAFW pump. The finding is of very low safety significance (Green) because there was no design deficiency, no actual loss of safety function, no single train loss of safety function for greater than the TS allowed outage time, and no risk due to external events. Additionally, the inspectors determined that the finding had a cross-cutting area aspect in the area of problem identification and resolution. Specifically, the licensee failed to thoroughly evaluate the problem with water ingress into the oil, such that a resolution addressed the cause and extent of condition (P.1(c)).
(Section 4OA5.2.b.1)

Cornerstone: Other

- Green. The inspectors identified a finding of very low safety significance and an associated Non-Cited Violation of 10 CFR 72.48(c)(1) for the licensee's failure to obtain a Certificate of Compliance (CoC) amendment pursuant to 10 CFR 72.244, for changes made in the spent fuel storage cask operating procedures during the 2004 loading campaign as described in the Final Safety Analysis Report. The procedure changes constituted a change in the terms, conditions, or specifications incorporated in the CoC. Although the procedures were contained in the Final Safety Analysis Report, the licensee failed to identify that TS 1.2.17a, "32PT Dry Storage Canister (DSC) Vacuum Drying Duration Limit," was also affected by the procedure change and required prior NRC approval. The licensee implemented corrective actions, which included revising the loading procedure to reflect the sequence described in the FSAR prior to the next cask loading campaign.

  This finding is more than minor because it had the potential to impact the NRC's ability to perform its regulatory function, since the licensee failed to receive NRC approval for a change in this licensed activity. The inspectors determined that the finding was not suitable for SDP evaluation because the noncompliance involved 10 CFR Part 72 dry fuel storage activities. Therefore, this finding was reviewed by regional management and dispositioned using traditional enforcement. The finding was determined to be of very low safety significance (Green). (Section 4OA5.5)

B. Licensee-Identified Violations

No violations of significance were identified.

REPORT DETAILS

Summary of Plant Status

Unit 1 was at 100 percent power throughout the inspection period with the exception of brief reductions in power during routine auxiliary feedwater pump and secondary system valve testing.

Unit 2 was at 100 percent power throughout the inspection period with the exception of brief reductions in power during routine auxiliary feedwater pump and secondary system valve testing.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Readiness For Impending Adverse Weather Condition – High Wind Conditions

a. Inspection Scope

Because high winds were forecast in the vicinity of the facility for October 18, 2007, the inspectors reviewed the licensee's overall preparations for the expected weather conditions. The inspectors walked down important outdoors areas within the protected area, in addition to the licensee's emergency alternating current (AC) power systems, because safety-related functions could be affected by, or required as a result of, high winds or tornado-generated missiles. The inspectors focused on the licensee's procedures used to respond to specified adverse weather conditions and toured the plant grounds for loose debris, which could become missiles during a tornado or high winds condition. The inspectors evaluated the licensee's preparations against the site's procedures and evaluated the adequacy of the staff's response. The inspectors also verified that the licensee was identifying adverse weather issues at an appropriate threshold and entering them into its corrective action program in accordance with station procedures.

This inspection constituted one sample prior to the onset of an adverse weather.

b. Findings

Introduction: The inspectors identified a finding of very low safety significance (Green) for the licensee's failure to control loose materials in the protected area. Specifically, the inspectors identified materials that were classified as tornado hazards per licensee procedure PC 99 and were near the Unit 1 and Unit 2 main and auxiliary transformers and the switchyard boundary. No violation of regulatory requirements occurred.

Description: On October 18, 2007, the inspectors conducted a walkdown of the risk significant portions of the main and auxiliary power system to assess the licensee's preparations to preclude or minimize potential damage from high winds associated with severe storms or tornadoes. During the walkdown, the inspectors identified a significant quantity of unsecured materials meeting the definition of tornado hazards provided in

Point Beach procedure PC 99, “Tornado Hazards Inspection Checklist,” near the subject transformers. The inspectors concluded that high winds or tornadoes combined with the proximity of the transformers to the large quantity of unsecured materials increased the potential to damage the transformers or related electrical equipment. The inspectors informed the licensee of the concern and the licensee took immediate corrective action to clean the areas identified by the inspectors and entered the issue into the corrective action program as corrective action program document (CAP, condition report) CAP 01114731. The licensee also commenced a walkdown of outside areas within the protected area to address extent of condition. In addition, the licensee initiated a procedure change request to incorporate tornado hazard walkdowns into Abnormal Operating Procedure (AOP) 13C, “Severe Weather Conditions.”

Analysis: The inspectors determined that the failure of licensee personnel to control material in the protected area near risk significant equipment is a performance deficiency. Using the guidance contained in Inspection Manual Chapter (IMC) 0612, “Power Reactor Inspection Reports.” Appendix B, “Issue Disposition Screening,” dated September 20, 2007, the inspectors determined that the finding is more than minor because, if left uncorrected, the loose items in the vicinity of the main and auxiliary transformers, and near the switchyard, would become a more significant safety concern. The inspectors determined that the finding warranted evaluation using the Significance Determination Process (SDP) because the finding is associated with an increase in the likelihood of an initiating event.

The inspectors evaluated the finding using IMC 0609, Appendix A, Attachment 1, “Significance Determination of Reactor Inspection Findings for At-Power Situations,” dated January 10, 2008. Using the Phase 1 SDP worksheet for the Initiating Event Cornerstone, transient initiator contributor, the inspectors determined that the finding did not contribute to the likelihood of a primary or secondary system loss of coolant accident initiator; the finding did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available; and the finding did not increase the likelihood of a fire or internal or external flooding. Therefore, the finding is determined to be of very low safety significance (Green).

The inspectors performed a review of past corrective action program documents to assess the effectiveness of the licensee’s corrective actions to address similar issues. During this review, inspectors noted that an NRC-identified finding, 05000266/000301-2006004-01, was issued in July 2006 for a nearly identical issue related to the failure to control loose material in the protected area. Procedure PC 99 was created as a corrective action for that finding. In addition, inspectors noted that between May and September 2007, there have been a number of CAPs written as a result of the identification of tornado hazards in the protected area during the use of procedure PC 99. Consequently, the inspectors determined that the finding had a cross-cutting aspect in the area of problem identification and resolution. Specifically, the licensee failed to take appropriate corrective actions to address safety issues and adverse trends in a timely manner, commensurate with their safety significance and complexity (P.1(d)).

Enforcement: The failure to maintain the protected area free of tornado hazards was not an activity affecting quality subject to 10 CFR Part 50, Appendix B, nor was a procedure required by license conditions or TSs violated. Therefore, while a performance deficiency existed, no violation of regulatory requirements occurred. This is considered a finding of very low safety significance (FIN 05000266/2007005-01;

05000301/2007005-01). The licensee included this finding in its corrective action program as CAP 01114731.

.2 Winter Seasonal Readiness Preparations

a. Inspection Scope

The inspectors conducted a review of the licensee's preparations for winter conditions to verify that the plant's design features and implementation of procedures were sufficient to protect mitigating systems from the effects of adverse weather. Documentation for selected risk-significant systems was reviewed to ensure that these systems would remain functional when challenged by inclement weather. During the inspection, the inspectors focused on plant specific design features and the licensee's procedures used to prepare for the onset of cold weather. Additionally, the inspectors reviewed licensee corrective actions for areas in the plant which previously had cold weather issues. Cold weather protection equipment, such as the façade freeze heat tracing and temporary area heaters, were verified to be in operation when applicable. The inspectors also reviewed corrective action program items to verify that the licensee was identifying cold weather issues at an appropriate threshold and entering them into the corrective action program in accordance with procedures. The inspectors' reviews focused specifically on the following plant systems due to their risk significance or susceptibility to cold weather issues: main steam system and instrumentation, including the atmospheric steam dumps and the main steam isolation valve; emergency core cooling system, including the refueling water storage tank and associated piping; and the façade freeze system.

This inspection constituted one winter seasonal system readiness sample.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

The inspectors performed partial walkdowns of accessible portions of risk-significant systems to determine the operability of these systems. The inspectors utilized system valve lineup and electrical breaker checklists, tank level books, plant drawings, and selected operating procedures to determine whether the systems were correctly aligned to perform the intended design functions. The inspectors also examined the material condition of the components and observed operating equipment parameters to determine whether deficiencies existed. The inspectors reviewed completed work orders (WOs) and calibration records associated with the systems for issues that could affect component or train functions. The inspectors used the information in the appropriate sections of the Final Safety Analysis Report (FSAR) to determine the functional requirements of the system.

Partial system walkdowns of the following systems constituted two inspection procedure samples:

- Emergency diesel generator (EDG) G01 aligned to busses 1A05 and 2A05 while EDG G02 was out-of-service the week of October 22, 2007; and
- EDG G02 aligned to busses 1A05 and 2A05 while EDG G01 was out-of-service the week of November 19, 2007.

b. Findings

No findings of significance were identified.

.2 Semi-Annual Complete System Walkdown

a. Inspection Scope

In November 2007, the inspectors performed a complete system alignment inspection of the auxiliary feedwater (AFW) system for Units 1 and 2 to verify the functional capability of the system. This system was selected because it was considered both safety-significant and risk-significant in the licensee's probabilistic risk assessment. The inspectors walked down the system to review mechanical and electrical equipment line-ups, electrical power availability, system pressure and temperature indications, component labeling, component lubrication, component and equipment cooling, hangers and supports, operability of support systems, and to ensure that ancillary equipment or debris did not interfere with equipment operation. A review of past and outstanding WOs was performed to determine whether any deficiencies significantly affected system function. In addition, the inspectors reviewed the CAP database to ensure that system equipment alignment problems were being identified and appropriately resolved. The documents used for the walkdown and issue review are listed in the attached List of Documents Reviewed.

These activities constituted one complete system walkdown inspection procedure sample.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

The inspectors conducted fire protection walkdowns, which focused on the following attributes: the availability, accessibility, and condition of fire fighting equipment; the control of transient combustibles and ignition sources; and the condition and status of installed fire barriers. The inspectors selected fire areas for inspection based on the area's overall fire risk contribution, as documented in the Individual Plant Examination of External Events, or the potential of a fire to impact equipment that could initiate a plant transient.

In addition, the inspectors assessed these additional fire protection attributes during walkdowns: fire hoses and extinguishers were in the designated locations and available for immediate use; unobstructed fire detectors and sprinklers; transient material loading within the analyzed limits; and fire doors, dampers, and penetration seals in satisfactory condition. The inspectors also determined whether minor issues identified during the inspection were entered into the licensee's corrective action program.

The walkdown of the following selected fire zones constituted three inspection procedure samples:

- Unit 2 TDAF Room
- EDG G01 Room
- EDG G02 Room

b. Findings

No findings of significance were identified.

.2 Annual Fire Protection Drill Observation (71111.05A)

a. Inspection Scope

During this quarter, the inspectors observed two fire brigade activation drills: an October 9, 2007, drill scenario that simulated a fire in the Unit 2 2P-2C charging pump room and a November 26 drill scenario that simulated a fire in the unit common cable spreading room. The combined drill observations were used to determine the readiness of the plant fire brigade to fight fires. The inspectors verified that the licensee staff identified deficiencies, openly discussed them in a self-critical manner at the drill debriefs, and took appropriate corrective actions. Specific attributes evaluated were: (1) proper wearing of turnout gear and self-contained breathing apparatus; (2) proper use and layout of fire hoses; (3) employment of appropriate fire fighting techniques; (4) sufficient firefighting equipment brought to the scene; (5) effectiveness of fire brigade leader communications, command, and control; (6) search for victims and propagation of the fire into other plant areas; (7) smoke removal operations; (8) utilization of pre-planned strategies; (9) adherence to the pre-planned drill scenario; and (10) drill objectives.

These activities constituted one annual fire protection inspection sample.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07)

a. Inspection Scope

The inspectors reviewed the licensee's testing of the EDG G01 and G02 heat exchangers one month following their replacement to verify that potential deficiencies did not affect the licensee's ability to detect degraded performance, and to identify any common cause issues that had the potential to increase risk, and to ensure that the licensee was adequately addressing problems that could result in initiating events that would cause an increase in risk. The inspectors also verified that the new heat exchangers were less susceptible to lake grass fouling, than the original heat exchangers. The inspectors reviewed the licensee's observations as compared against acceptance criteria, the correlation of scheduled testing and the frequency of testing, and the impact of instrument inaccuracies on test results. Inspectors also verified that test acceptance criteria considered differences between test conditions, design conditions, and testing criteria.

This inspection constituted one inspection procedure sample.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

.1 Resident Inspector Quarterly Review

a. Inspection Scope

In November 2007, the inspectors observed a crew of licensed operators in the plant's simulator during licensed operator training to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems, and training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

- licensed operator performance;
- crew's clarity and formality of communications;
- ability to take timely actions in the conservative direction;
- prioritization, interpretation, and verification of annunciator alarms;
- correct use and implementation of abnormal and emergency procedures;
- control board manipulations;
- oversight and direction from supervisors; and
- ability to identify and implement appropriate TS actions and Emergency Plan actions and notifications.

The crew's performance in these areas was compared to pre-established operator action expectations and successful critical task completion requirements.

This inspection constituted one quarterly licensed operator requalification program sample.

b. Findings

No findings of significance were identified.

.2 Facility Operating History

a. Inspection Scope

The inspectors reviewed the plant's operating history from September 2005 through October 2007 to identify operating experience that was expected to be addressed by the

Licensed Operator Requalification Training (LORT) program. It was then verified that the identified operating experience had been addressed by the facility licensee in accordance with the station's approved Systems Approach to Training (SAT) program to satisfy the requirements of 10 CFR 55.59(c), "Requalification program requirements."

b. Findings

No findings of significance were identified.

.3 Licensee Requalification Examinations

a. Inspection Scope

The inspectors performed a biennial inspection of the licensee's LORT test/examination program for compliance with the station's SAT program that would satisfy the requirements of 10 CFR 55.59(c)(4), "Evaluation." The inspectors reviewed the 2006 biennial written requalification examinations and 2007 annual operating test material to evaluate general quality, construction, and difficulty level. The written examinations reviewed consisted of four written examinations, each containing 30 questions. The operating examination material consisted of 6 operating tests, each containing approximately two dynamic simulator scenarios and five job performance measures (JPMs). The inspectors reviewed the annual requalification operating test and biennial written examination material to evaluate general quality, construction, and difficulty level. The inspectors assessed the level of examination material duplication from week-to-week during the current year operating test and written examinations. The inspectors reviewed the methodology for developing the examinations, including the LORT program two-year sample plan, probabilistic risk assessment insights, previously identified operator performance deficiencies, and plant modifications.

b. Findings

No findings of significance were identified.

.4 Licensee Administration of Requalification Examinations

a. Inspection Scope

The inspectors observed the administration of a requalification operating test to assess the licensee's effectiveness in conducting the test to ensure compliance with 10 CFR 55.59(c)(4), "Evaluation." The inspectors evaluated the performance of one crew in parallel with the facility evaluators during one dynamic simulator scenario and evaluated various licensed crew members concurrently with facility evaluators during the administration of several JPMs. The inspectors assessed the facility evaluators' ability to determine adequate crew and individual performance using objective, measurable standards. The inspectors observed the training staff personnel administer the operating test, including conducting pre-examination briefings, evaluations of operator performance, and individual and crew evaluations upon completion of the operating test. The inspectors evaluated the ability of the simulator to support the examinations. A specific evaluation of simulator performance was conducted and documented under Section 1R11.9 of this report.

b. Findings

No findings of significance were identified.

.5 Examination Security

a. Inspection Scope

The inspectors observed and reviewed the licensee's overall licensed operator requalification examination security program related to examination physical security (e.g., access restrictions and simulator considerations) and integrity (e.g., predictability and bias) to verify compliance with 10 CFR 55.49, "Integrity of examinations and tests." The inspectors also reviewed the facility licensee's examination security procedure, any corrective actions related to past or present examination security problems at the facility, and the implementation of security and integrity measures (e.g., security agreements, sampling criteria, bank use, and test item repetition) throughout the examination process.

b. Findings

There was one issue associated with examination security identified by the licensee during the administration of JPMs during the sixth week of administration of the 2007 annual operating test. On October 31, 2007, an individual who had just completed a simulator JPM was escorted back to the waiting room area and dropped off. However, there was no examination sequesterer in the waiting room area to ensure that there was no examination compromise with individuals in the room who had not been administered the JPM. Within two minutes, the licensee identified the potential for an examination compromise. The licensee determined that the individual who had just been administered the JPM did not communicate any exam-related information to any other individuals who had not been administered the JPM. As part of its corrective actions, the licensee held a training department standdown with the members of the examination team. The licensee replaced the JPM in question for the remaining individuals to be tested. The issue was documented in the corrective action program as CAP 01115710.

The NRC was appropriately notified of the issue. The issue was reviewed and assessed for a possible violation of 10 CFR 55.49, "Integrity of examinations and tests." With the actions taken, it was determined that no actual examination compromise had occurred. The issue was not subject to enforcement action in accordance with NRC enforcement policy.

.6 Licensee Training Feedback System

a. Inspection Scope

The inspectors assessed the methods and effectiveness of the licensee's processes for revising and maintaining its LORT program up-to-date, including the use of feedback from plant events and industry experience information. The inspectors reviewed the licensee's quality assurance oversight activities, including licensee training department self-assessment reports. The inspectors evaluated the licensee's ability to assess the effectiveness of its LORT program and its ability to implement appropriate corrective actions. This evaluation was performed to verify compliance with 10 CFR 55.59(c) "Requalification program requirements", and the licensee's SAT program.

b. Findings

No findings of significance were identified.

.7 Licensee Remedial Training Program

a. Inspection Scope

The inspectors assessed the adequacy and effectiveness of the remedial training conducted since the previous biennial requalification examinations and the training from the current examination cycle to ensure that they addressed weaknesses in licensed operator or crew performance identified during training and plant operations. The inspectors reviewed remedial training procedures and individual remedial training plans. This evaluation was performed in accordance with 10 CFR 55.59(c), "Requalification program requirements," and with respect to the licensee's SAT program.

b. Findings

No findings of significance were identified.

.8 Conformance with Operator License Conditions

a. Inspection Scope

The inspectors reviewed the facility and individual operator licensees' conformance with the requirements of 10 CFR Part 55. The inspectors reviewed the facility licensee's program for maintaining active operator licenses and to assess compliance with 10 CFR 55.53(e) and (f). The inspectors reviewed the procedural guidance and the process for tracking on-shift hours for licensed operators and which control room positions were granted watch-standing credit for maintaining active operator licenses. The inspectors reviewed the facility licensee's LORT program to assess compliance with the requalification program requirements as described by 10 CFR 55.59(c). Additionally, medical records for seven licensed operators were reviewed for compliance with 10 CFR 55.53(i).

b. Findings

No findings of significance were identified.

.9 Conformance with Simulator Requirements

a. Inspection Scope

The inspectors assessed the adequacy of the licensee's simulation facility (simulator) for use in operator licensing examinations and for satisfying experience requirements as prescribed in 10 CFR 55.46, "Simulation facilities." The inspectors also reviewed a sample of simulator performance test records (i.e., transient tests, malfunction tests, and core performance tests), simulator discrepancies, and the process for ensuring continued assurance of simulator fidelity in accordance with 10 CFR 55.46. The inspectors reviewed and evaluated the discrepancy process to ensure that simulator fidelity was maintained. Open simulator discrepancies were reviewed for importance relative to the impact on 10 CFR 55.45 and 55.59 operator actions, as well as on nuclear and thermal hydraulic operating characteristics. The inspectors interviewed the licensee's simulator staff about the configuration control process and completed the Inspection Procedure 71111.11, Appendix C checklist, to evaluate whether the licensee's plant-referenced simulator was operating adequately as required by 10 CFR 55.46(c) and (d).

b. Findings

No findings of significance were identified.

.10 Annual Operating Test Results

a. Inspection Scope

The inspectors reviewed the overall pass/fail results of the annual JPM operating tests, and the annual simulator operating tests (required to be given per 10 CFR 55.59(a)(2)) administered by the licensee during 2007. The overall results were compared with the SDP in accordance with IMC 0609, Appendix I, "Operator Requalification Human Performance Significance Determination Process (SDP)," dated August 22, 2005. The year 2007 was the first year of the licensee's 24-month training program; therefore, no written examination was administered in 2007.

This represented one sample.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13)

a. Inspection Scope

The inspectors reviewed risk assessments for planned and emergent maintenance activities during the specified work weeks. 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 assessed whether evaluation, planning, control, and performance of the work were done in a manner to reduce the risk and minimize the duration, where practical, and whether 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 whether the equipment configurations were properly listed. The inspectors also verified that protected equipment was identified and controlled as appropriate and that significant aspects of plant risk were communicated to the necessary personnel.

The reviews of maintenance risk assessment and emergent work evaluation constituted five inspection procedure samples:

- Planned and emergent maintenance during the week of October 15, 2007;
- Planned and emergent maintenance during the week of October 22;
- Planned and emergent maintenance during the week of October 29;
- Planned and emergent maintenance during the week of November 26; and
- Planned and emergent maintenance during the week of December 10.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

.1 Service Water (SW) Pump P-32C Issues

a. Inspection Scope

The inspectors reviewed CAP 01098680, its associated operability evaluation (OPR), apparent cause evaluation (ACE), and past operability evaluation in the licensee's corrective action program. The inspectors reviewed design basis information, the FSAR, TS requirements, and licensee procedures to determine the technical adequacy of the operability evaluations. The inspectors also reviewed the licensee's implementation of select sections of the American Society of Mechanical Engineers (ASME) Operational Maintenance (OM) Code, 1995 Addenda, to evaluate whether requirements were met and the appropriate actions were taken in accordance with the Code. In addition, the inspectors determined whether compensatory measures were implemented, as required. The inspectors assessed whether system operability was properly justified and that the system remained available, such that no unrecognized increase in risk occurred.

This review constituted one sample.

b. Findings

Introduction: A self-revealing finding with no associated violation of regulatory requirements was identified for an inadequate operability evaluation issued on June 28, 2007, associated with safety-related SW pump P-32C. Specifically, P-32C failed its inservice test (IST) on high vibrations after only 6.5 hours of operation, but the June 2007 operability evaluation had concluded that the pump would remain operable and not reach the IST out-of-service limit until 120 hours of continuous operation. The licensee's non-conservative decision-making and use of a non-conservative prediction model led to the incorrect conclusion of operability of the P-32C pump. Had the licensee used an appropriate prediction model, reflective of a degraded/degrading pump, the OPR would have concluded the pump was inoperable.

Description: Service water pump P-32C was placed on increased IST frequency after trending into the IST Alert Range in May 2007. On June 24, 2007, during the next performance of increased frequency testing, P-32C vibration was recorded at 0.3051 inches per second (ips) compared to the Required Action limit of $\geq$ 0.327 ips. Because this vibration measurements approaching this out-of-service limit of the pump, OPR 01098680 was performed to: review the vibration trend and determine the additional run time until the IST out-of-service limit might be reached, compare this duration to the mission time of the P-32C pump, and determine if any additional compensatory measures were required to be taken.

Licensee engineers utilized vibration analysis software to predict the point at which P-32C would exceed the 0.327 ips out-of-service limit. Based on the licensee's assumption that the degrading vibration trend was due to normal bearing wear, the trend projection grossly overestimated the pump's remaining acceptable run time. Specifically, the model predicted that an additional 120 hours, or five days, of continuous operation could be achieved before reaching 0.327 ips. On August 8, 2007, however, the next increased frequency IST was performed on P-32C and a vibration level of 0.4055 ips was observed. Because this value exceeded the 0.327 ips IST out-of-service limit, P-32C was declared inoperable and the appropriate TS action statement was entered. The pump was subsequently rebuilt and returned to service on August 11 after 71 hours of unavailability.

The inspectors reviewed ACE 01098680-02. The purpose of this ACE was to determine the cause of the unexpected step change in vibrations and to determine why vibrations exceeded the IST out-of-service limit in only 6.5 hours vice the 120 hours of predicted run time. From the review, the inspectors concluded that the licensee applied non-conservative assumptions to the vibration trend projection when it failed to factor in vibration amplifying resonance effects, or any additional conservative margin for uncertainty.

The inspectors identified another example of the licensee's non-conservative decision-making. Specifically, the licensee's OPR did not conservatively address the 30-day design basis mission time of the SW pumps when the IST out-of-service limit was predicted to be reached in less than the full 30-day mission time. Section ISTB 6.2.2 of the Code states: "If the measured test parameter values fall within the required action range, the pump shall be declared inoperable until either the cause of the deviation has been determined and the condition is corrected, or an analysis of the pump is performed and new reference values are established in accordance with paragraph ISTB 4.6." of the Code. The licensee did not declare P-32C inoperable when it was identified that the vibration parameters would exceed the required action limit within the 30-day mission time of the pump, nor were new baseline values established in accordance with the Code.

<u>Analysis</u>: The inspectors determined that the failure to use appropriate, conservative, calculation assumptions in the trend projection to justify the basis for the continued operability of a safety-related-pump, is a performance deficiency and a finding. The finding is more than minor because it could reasonably be viewed as a precursor to a significant event.

Using IMC 0609, "Significance Determination Process," dated January 10, 2008, the inspectors determined that the finding is of very low safety significance (Green) because the finding did not involve a design deficiency, there was no actual loss of safety function, no single train loss of safety function for greater than the TS-allowed outage time, and no risk due to external events.

Additionally, the inspectors determined that the finding had a cross-cutting aspect in the area of human performance. Specifically, the licensee failed to use conservative assumptions in making decisions affecting the operability of safety-related components (H.1(b)).

Enforcement: The failure to perform an adequate operability evaluation, which was based upon non-conservative decision-making and a non-conservative trend projection, was not a violation of regulatory requirements although a performance deficiency existed. Therefore, this issue is considered a finding of very low safety significance (FIN 05000266/2007005-02; 05000301/2007005-02).

The licensee included this finding in its corrective action program as CAP 01119241 and has actions planned to perform an ACE to address the use of IST trend data in OPRs.

.2 Operability Evaluations for the Unit 2 TDAFW Pump 2P-29 Following Overhaul

a. Inspection Scope

The inspectors reviewed selected immediate operability evaluations and operability evaluations associated with issues entered into the licensee's corrective action program. The inspectors reviewed design basis information, the FSAR, TS requirements, and licensee procedures to determine the technical adequacy of the operability evaluations. In addition, the inspectors determined whether compensatory measures were implemented, as required. The inspectors assessed whether system operability was properly justified and that the system remained available, such that no unrecognized increase in risk occurred.

The reviews of the following OPRs constituted six samples:

- CAP 01112660, 2P-29 Outboard Bearing Water Following IT-09A, dated September 24, 2007;
- CAP 01113318, IT-09A Oil Analysis Results Not as Expected for 2P-29, dated September 27, 2007;
- OPR1098358, Moisture Observed in Oil Sample From 2P-29 Outboard Bearing, Revision 2, dated November 3, 2007;
- OPR1098358, Moisture Observed in Oil Sample From 2P-29 Outboard Bearing, Revision 3, dated November 4, 2007;
- OPR1098358, Moisture Observed in Oil Sample From 2P-29 Outboard Bearing, Revision 4, dated November 7, 2007; and
- OPR1098358, Moisture Observed in Oil Sample From 2P-29 Outboard Bearing, Revision 5, dated November 10, 2007.

b. Findings

Introduction: The inspectors identified a finding of very low safety significance (Green) and an associated Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," for the failure to adequately assess operability of the Unit 2 TDAFW pump in accordance with plant procedures. The inspectors identified that the licensee failed to implement procedural requirements regarding the immediate assessment of operability on September 24 and September 27, 2007, for the increased water ingress into the turbine outboard bearing housing for the pump following maintenance.

Description: On September 24, 2007, following the overhaul of the 2P-29 TDAFW pump, an oil sample was taken from the outboard bearing housing, after a four-hour run. CAP 01112660 was written, which documented that an estimated water volume in the oil sample based on visual indication was approximately 1,000 to 1,500 parts per million (ppm) for the four-hour run. The CAP description concluded that this was an expected condition. A second shorter pump run was performed and the water content in the oil was visually estimated to be approximately 100 ppm of water. The licensee rationalized that the initial water content was expected and the condition report was closed with no further actions taken. However, the inspectors identified that neither the operations nor engineering staff questioned why a visual estimate for indication of water in the oil would have produced five times the amount of water in the oil immediately following the overhaul, as compared to the first oil sample taken in June 2007 following a November 2006 overhaul, which showed 300 ppm water in the oil. The June 2007 outboard oil sample for the 2P-29 turbine was the first time the oil was sampled since the November 2006 overhaul and the first time water ingress was noted in the turbine outboard bearing.

On September 27, CAP 01113318 was written and documented that the outboard oil sample from the first four-hour run, analyzed by a laboratory, contained 20,040 ppm of water (approximately two percent by volume). The CAP description also noted that the number was not consistent with the visual estimate from September 24 of 1,000 to 1,500 ppm. However, the CAP dismissed the results, based on conjecture, concluding that the 20,040 ppm results were false readings due to a laboratory error or an accidental capture of water droplets during the sampling process. The CAP concluded that “the indicated levels of water in the IT-09A sample are errant.” The immediate operability assessment concluded that based on the information provided in the description section there were no operability concerns. In addition, the assessment discussed that the pump was tested satisfactorily, with no abnormal indications observed during the run. The inspectors, as well as the licensee personnel performing the causal evaluation for this issue, concluded that the increased water first observed on September 24 should not have been discounted and was discounted due to confirmational biases, resulting in nonconservative assumptions in the evaluation of this condition.

The inspectors reviewed the licensee’s procedure for operability, Fleet Procedure FP OP-OL-01, “Operability Determination.” The procedure required a determination if a condition existed that could call into question the ability of a structure, system, or component (SSC) to perform its specified safety function. An example of such a condition was an item which met the definition of a degraded condition. A degraded condition, as defined in the fleet procedure, was a condition where there had been a noticeable change in parameters that were precursors to failure. The attachment guidance for immediate operability review also highlighted questions for performing operability determinations, which included the following: “Could the capability of a SSC to prevent or mitigate consequences of an accident as postulated in the Final Safety Analysis Report be reduced?” The guidance suggested that an OPR should be requested if additional engineering evaluation and justification was needed to answer those questions. Finally, the inspectors noted that the guidelines for operability recommendations included guidance to evaluate trend data to identify a deteriorating condition and to utilize an OPR to predict the point when a SSC may become inoperable. The inspectors concluded the licensee had not adequately implemented the procedures for operability determinations for the September 24 and 27 CAPs. The licensee had not assessed the parameter of a significant increase in the ingress of water following a maintenance overhaul, as compared to the last maintenance overhaul.

On November 1, 2007, approximately 5 weeks after the maintenance overhaul, the licensee ran 2P-29 for about two hours and then sampled the oil. The outboard oil sample had 29,515 ppm of water in the oil. The licensee declared the pump inoperable and revised the July 2007 operability evaluation for the original water ingress issue in June.

On November 3, the licensee issued Revision 2 to OPR1098358 and the pump was determined to be capable of performing the design functions for the design basis mission time of eight hours. On November 4, Revision 3 to OPR1098358 was issued to specify a compensatory measure of testing the pump every 72 hours for an eight-hour duration. The subsequent pump runs continued to show high levels of water in the outboard bearing oil. The inspectors identified that Revisions 2 and 3 utilized data from 2P-29 on water ingress rates prior to the September 2007 turbine overhaul. These values were not applicable to the current condition, because the September maintenance had created a new and greater water ingress problem. Revision 4 to OPR1098358, issued on November 7, was a rewrite of the OPR utilizing current oil analysis data from after the overhaul. In addition, the licensee hypothesized, as part of the operability discussion, that differences in water concentrations in the oil seen since November 1 were likely the result of a change in sampling techniques. However, the inspectors noted that these theories were refuted by visual observation and comparison of the quarantined oil samples taken since November 1. Further testing of the previous oil samples also refuted the sampling technique theories. In addition, the inspectors noted that the licensee did not have any established procedural controls or work instructions for mixing of the samples and splitting of the samples to ensure quality control. The licensee initiated a condition report and took immediate corrective actions to address this latter issue. Revision 5 to the OPR was issued on November 10 and contained additional discussion on the potential for an unexpected increase in steam leakage, and additional information related to the sampling technique and testing duration.

The inspectors noted that for all the revisions, the OPR demonstrated that the TDAFW pump would have performed the required safety functions for the eight-hour mission time of the FSAR Chapter 14 design basis accidents. However, the inspectors pointed out to the licensee that the OPR did not address all the safety functions required to be performed by the TDAFW pump, which at Point Beach included several fire-related scenarios. The licensee subsequently initiated a CAP for this issue.

Additional information regarding the issues associated with the 2P-29 TDAFW pump is documented in Section 4OA5.2 of this report.

Analysis: The inspectors determined that the failure to adequately perform an operability determination was a performance deficiency and a finding that warranted a significance evaluation. Using IMC 0612, “Power Reactor Inspection Reports,” Appendix B, “Issue Screening,” dated September 20, 2007, the inspectors determined that the finding is more than minor because, if left uncorrected, the failure to properly assess operability would result in the TDAFW pump being degraded and potentially inoperable, exceeding the allowed outage time in accordance with TSs.

Using IMC 0609, Appendix A, “Determining the Significance of Reactor Inspection Findings for At-Power Situations,” dated January 10, 2008, the inspectors determined the finding may have resulted in a late determination of an actual loss of safety function of a system or train of equipment. The risk assessment for the potential loss of safety function is attributed to the performance deficiencies associated with inadequate maintenance discussed in Section 4OA5.2.b.2 as URI 5000266/2007005-07. This did not cause the loss of safety function for greater than the allowed outage time. Therefore, the finding is considered to be of very low safety significance (Green). Additionally, the inspectors determined that the finding has a cross-cutting aspect in the area of human performance. Specifically, the licensee failed to use conservative assumptions in decision-making affecting operability of safety-related equipment (H.1(b)).

Enforcement: 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” requires, in part, that activities affecting quality be prescribed and accomplished by procedures appropriate to the circumstances. The licensee failed to implement the operability determination procedure FP-OP-OL-01, “Operability Determination.” The procedure required, in part, that the licensee assess the capability of a SSC to prevent or mitigate consequences of an accident as postulated in the FSAR. Contrary to this, the licensee failed to adequately assess the operability of the turbine outboard bearing for the Unit 2 TDAFW pump following increased water intrusion during post-maintenance testing on September 24, 2007, and later corroborated by oil analyses on September 27. Because this finding was of very low safety significance (Green) and because it was entered into the licensee’s corrective action program (as CAP 01115748), this violation is being treated as a Non-Cited Violation, consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000301/2007005-03).

The licensee took immediate corrective actions to address the issue, and at the end of the inspection period the licensee continued to evaluate the causes associated with this finding.

.3 Operability Evaluations

a. Inspection Scope

The inspectors reviewed selected operability evaluations associated with issues entered into the licensee’s corrective action program. The inspectors reviewed design basis information, the FSAR, TS requirements, and licensee procedures to determine the technical adequacy of the operability evaluations. In addition, the inspectors determined whether compensatory measures were implemented, as required. The inspectors assessed whether system operability was properly justified and that the system remained available, such that no unrecognized increase in risk occurred.

The reviews of the following operability evaluations constituted four samples:

- CAP 00889745, Degraded Grid Voltage Concerns;
- CAP 01111251, Discrepancy in Control Room Accident Fan Brake Horsepower Versus Vendor Data Used in Calculation 2004-0002, Revision 6;
- CAP 01114308, Unit 1 and 2 Safety Injection Valves 850A/B, Sump B Suction Valve Limit Switches; and
- CAP 01116453, Unit 2 W-3B Control Rod Drive Shroud Fan Tripped on Overcurrent.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17)

.1 Annual Resident Review

a. Inspection Scope

The following engineering design package was reviewed and selected aspects were discussed with engineering personnel:

- EDG G-01 and G-02 heat exchanger modification

This document and related documentation were reviewed to assess adequacy of the associated 10 CFR 50.59 safety evaluation screening; consideration of design parameters; implementation of the modification; post-modification testing, and proper updating of procedures, design, and licensing documents. The inspectors observed ongoing and completed work activities to verify that installation was consistent with the design control documents. The modifications were installed to address a longstanding operator workaround for lake grass fouling of the heat exchangers.

This inspection constituted one sample.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

During completion of the post-maintenance test inspection procedure samples, the inspectors observed in-plant activities and reviewed procedures and associated records to determine whether:

- Testing activities satisfied the test procedure acceptance criteria;
- Effects of the testing were adequately addressed prior to the testing;
- Measuring and test equipment calibration was current;
- Test equipment was 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 and 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; and
- All problems identified during the testing were appropriately entered into the corrective action program.

The activities listed below were reviewed by the inspectors and constituted three quarterly inspection procedure samples:

- Unit 1 Charging Pump P-2A;
- Unit 1 Charging Pump P-2B Variable Frequency Drive; and
- Service Water Pump P-32E.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

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

- Preconditioning occurred;
- Effects of the testing were 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 were in accordance with TSs, the 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 frequencies met TS requirements to demonstrate operability and reliability;
- 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 and results were accurate, complete, within limits, and valid;
- Test equipment was removed after testing;

- Where applicable for IST activities, testing was performed in accordance with the applicable version of Section XI, American Society of Mechanical Engineers Code, 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 was declared inoperable;
- Where applicable for safety-related instrument control surveillance tests, reference setting data were accurately incorporated in the test procedure;
- Where applicable, actual conditions encountering high resistance electrical contacts were such that the intended safety function could still be accomplished;
- 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.

During this inspection period, the inspectors completed the following inspection procedure samples, which included two routine surveillances, two inservice tests, and one containment isolation valve test, for a total of five quarterly inspection procedure samples:

- EDG G01 surveillance testing during the week of October 22, 2007;
- Unit 2 TDAFW pump 2P-29 ISTs on November 1 and 2;
- Unit 2 TDAFW pump 2P-29 ISTs on November 7;
- EDG G02 surveillance testing during the week of November 11; and
- Testing of Unit 2 containment isolation valve SC-966.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed the following temporary modification:

- Furmanite injection of Unit 2 Moisture Separator Reheater Purge Valve 2MS-32A.

The inspectors compared the temporary configuration changes and associated 10 CFR 50.59 screening and evaluation information against the design basis, the FSAR, and the TS, as applicable, to verify that the modification did not affect the operability or availability of the affected system. The inspectors also compared the licensee's information to operating experience information to ensure that lessons learned from other utilities had been incorporated into the licensee's decision to implement the temporary modification. The inspectors, as applicable, performed field verifications to ensure that the modifications were installed as directed; the modifications operated as expected; modification testing adequately demonstrated continued system operability, availability, and reliability; and that operation of the modifications did not impact the operability of any interfacing systems. Lastly, the inspectors discussed the temporary modification with operations, engineering, and training personnel to ensure that the individuals were aware of how extended operation with the temporary modification in place could impact overall plant performance.

This inspection constituted one sample.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

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

a. Inspection Scope

The inspectors performed a screening review of the 2006 and 2007 revisions to the Point Beach Emergency Plan Manual to determine whether the changes decreased the plan's effectiveness. This review did not constitute an approval of the changes, and as such, the changes are subject to future NRC inspection to ensure that the emergency plan continues to meet NRC regulations.

These activities completed one inspection sample.

b. Findings

No findings of significance were identified

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS3 Radiation Monitoring Instrumentation and Protective Equipment (71121.03)

.1 Inspection Planning

a. Inspection Scope

The inspectors reviewed the FSAR to identify applicable radiation monitors associated with measuring transient high and very high radiation areas, including those intended for remote emergency assessment. The inspectors identified the types of portable radiation detection instrumentation used for job coverage of high radiation area work, including instruments used for underwater surveys, portable and fixed area radiation monitors used to provide radiological information in various plant areas, and continuous air monitors used to assess airborne radiological conditions and, consequently, work areas with the potential for workers to receive a 50 millirem or greater committed effective dose equivalent (CEDE). Whole body counters used to monitor for internal exposure and those radiation detection instruments utilized to conduct surveys for the release of personnel and equipment from the radiologically controlled area (RCA), including contamination monitors and portal monitors, were also identified.

These reviews represented two inspection samples.

b. Findings

No findings of significance were identified.

.2 Walkdowns of Radiation Monitoring Instrumentation

a. Inspection Scope

The inspectors conducted walkdowns of selected area radiation monitors (ARMs) in the Unit 1 and Unit 2 auxiliary building to determine if these monitors were located and provided measurement capability as described in the FSAR and were optimally positioned relative to the potential sources of radiation they were intended to monitor. Walkdowns were conducted of those areas where portable survey instruments were source checked and maintained for radiation protection (RP) staff use to determine if those instruments designated “ready for use” were sufficient in number to support the RP program, had current calibration stickers, were operable, and were in adequate physical condition. Also, the inspectors observed the licensee’s portable survey instrument calibration units and the radiation sources used for operability checks of various radiation measuring instruments to assess their material condition and discussed their use with RP staff to determine if they were used appropriately. Additionally, the inspectors observed the use of the instrument calibration units, discussed with the staff calibrator output validation methods, and compared calibrator exposed readings with calculated/expected values. The inspectors evaluated compliance with licensee procedures while RP personnel demonstrated the methods for performing source checks of portable survey instruments and source checks of personnel contamination and portal monitors located at the egress to the RCA and the plant protected area.

These reviews represented one partial inspection sample, which combined with Section 2OS3.3 constituted one sample.

b. Findings

No findings of significance were identified.

.3 Calibration and Testing of Radiation Monitoring Instrumentation

a. Inspection Scope

The inspectors selectively reviewed radiological instrumentation associated with monitoring transient high and/or very high radiation areas, instruments used for remote emergency assessment, and radiation monitors used to identify personnel contamination and for assessment of internal exposures to verify that the instruments had been calibrated as required by the licensee’s procedures, consistent with industry and regulatory standards. The inspectors also reviewed alarm setpoints for selected ARMs, for personnel contamination monitors and for portal (egress) monitors to verify that they were established consistent with the FSAR or TSs, as applicable, and were consistent with industry practices and regulatory guidance. Specifically, the inspectors reviewed calibration procedures and the most recent calibration records for the following radiation monitoring instrumentation and calibration equipment:

- Unit 1 and Unit 2 Containment High Range (Accident) Radiation Monitors;
- Unit 1 and Unit 2 Charging Pump Room Low and High Range ARMs;
- Unit 1 and Unit 2 Seal Table ARMs;
- Unit 1 and Unit 2 Post-Accident Sample Line Monitors;
- Common Unit Safety Injection Pump Room Low and High Range ARMs;
- Portable Gamma and Neutron Survey Instruments (Model AMP-100 and ASP-1);
- Portable Air Sampler (Model AMS-4);
- Portal (Gamma) Monitors Used at RCA and Protected Area Egresses;
- Personnel Contamination Monitors Used at RCA Egress;
- Two Instrument Calibrators (and the associated instruments used to measure calibrator output); and
- Whole Body Counter.

The inspectors determined what actions were taken when, during calibration or source checks, an instrument was found significantly out of calibration or exceeded as-found acceptance criteria. Should that occur, the inspectors verified that the licensee's actions would include a determination of the instruments previous uses and the possible consequences of that use since the prior calibration. The inspectors also reviewed the results of the licensee's most recent 10 CFR Part 61 source term (radionuclide mix) evaluation to determine if instrument/monitor calibration and check sources were representative of the plant source term. Given that source term, the inspectors reviewed the licensee's method for internal dose assessment to determine if difficult to detect nuclides were scaled into whole body count dose determinations.

These reviews represented one partial inspection sample, which combined with Section 2OS3.2 constituted one sample.

b. Findings

No findings of significance were identified.

.4 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed corrective action documents and any special reports that involved personnel contamination monitor alarms due to personnel internal exposures to determine whether identified problems were entered into the corrective action program for resolution. Licensee self-assessments, audits, and corrective action documents were also reviewed to determine if problems with radiological instrumentation or with self-contained breathing apparatus (SCBA) were identified, characterized, prioritized, and resolved effectively using the corrective action program.

While no internal exposure with a CEDE greater than 50 millirem occurred since the last inspection in this area, the inspectors reviewed the licensee's methodology for internal dose assessment.

The inspectors reviewed corrective action program reports related to exposure-significant radiological incidents that involved radiation monitoring instrument deficiencies since the last inspection in this area, as applicable. Members of the RP staff were interviewed and corrective action documents were reviewed to determine whether follow-up activities were being conducted in an effective and timely manner commensurate with their importance to safety and risk based on the following:

- Initial problem identification, characterization, and tracking;
- Disposition of operability/reportability issues;
- Evaluation of safety significance/risk and priority for resolution;
- Identification of repetitive problems;
- Identification of contributing causes;
- Resolution of Non-Cited Violations tracked in the corrective action program; and
- Identification and implementation of effective corrective actions.

The inspectors determined if the licensee's self-assessment and audit activities completed for the approximate two-year period that preceded the inspection were identifying and addressing repetitive deficiencies or significant individual deficiencies in problem identification and resolution, as applicable.

These reviews represented three inspection samples.

b. Findings

No findings of significance were identified.

.5 RP Technician Instrument Use

a. Inspection Scope

The inspectors selectively determined whether calibrations for those survey instruments used to perform job coverage surveys and for those currently designated for use had not lapsed. The inspectors reviewed instrument issue logs for selected dates in 2007 to determine if response checks of portable survey instruments and checks of instruments used for unconditional release of materials and workers from the RCA were completed prior to instrument use, or daily, as required by the licensee's procedure. The inspectors also discussed instrument calibration methods and source response check practices with radiation protection staff and observed staff demonstrate instrument source checks.

These reviews represented one inspection sample.

b. Findings

No findings of significance were identified.

.6 SCBA Maintenance/Inspection and Emergency Response Staff Qualifications

a. Inspection Scope

The inspectors reviewed aspects of the licensee's respiratory protection program for compliance with the requirements of Subpart H of 10 CFR Part 20 and to determine if SCBA equipment was properly inspected, maintained, and ready for emergency use. The inspectors reviewed records of inspection and functional tests performed in 2006 and 2007 for all SCBAs staged in the plant to support both the licensee's fire brigade and emergency response organization, as provided in the Point Beach Emergency Plan.

The inspectors evaluated the licensee's capabilities for refilling and transporting SCBA air bottles to and from the control room during emergency conditions. The inspectors determined if control room staff designated for the active on shift duty roster were trained, respirator fit-tested, and medically certified to use SCBAs. Additionally, the inspectors reviewed SCBA qualification records for the licensee's radiological emergency teams, including the radiation protection, chemistry, and maintenance staffs, to determine if a sufficient number of staff were qualified to fulfill emergency response positions consistent with the Emergency Plan and the requirements of 10 CFR 50.47. The inspectors also reviewed the respiratory protection training lesson plan to assess its overall adequacy relative to Subpart H of 10 CFR Part 20.

The inspectors walked down SCBA equipment maintained in the control room, the Operations Support Center, various areas of the turbine building and in the warehouse fire brigade ready rooms, as well as spare SCBA air bottle stations. During these walkdowns, the inspectors examined numerous SCBA units to assess their material condition and to determine if air bottle hydrostatic tests were current and if bottles were pressurized to meet procedural requirements. The inspectors reviewed records of SCBA equipment inspection and functional testing, including results of the most recent regulator flow tests for all SCBA units maintained at the site. Additionally, the inspectors observed members of the licensee's operations and RP staffs demonstrate the methods used to conduct the inspections and functional tests to determine if these activities were performed consistent with procedure and the equipment manufacturer's recommendations. The inspectors also evaluated through record review and observations if the required air cylinder hydrostatic testing was documented and current, if the Department of Transportation required retest air cylinder markings were in place for numerous randomly selected SCBA units and spare air bottles, and if air quality for the compressor used to fill SCBA air bottles was routinely tested to verify Grade-D quality. The inspectors also reviewed the qualification documentation (training certificate) issued by the SCBA manufacturer to an individual contracted by the licensee to perform maintenance/repair of SCBA vital components. Pressure regulator test/repair records for 2007 for all SCBA units designated for emergency use were reviewed to determine if the equipment was adequately maintained consistent with the manufacturer's maintenance procedure.

These reviews represented two inspection samples.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification (71151)

.1 Data Submission Issue

a. Inspection Scope

The inspectors performed a review of the data submitted by the licensee for the 4th quarter 2007 PIs for any obvious inconsistencies prior to its public release in accordance with IMC 0608, "Performance Indicator Program."

This review was performed as part of the inspectors' normal plant status activities and, as such, did not constitute a separate inspection sample.

b. Findings

No findings of significance were identified.

.2 Mitigating Systems Performance Index - Emergency AC Power System

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index (MSPI) Emergency AC Power System PIs, for both Units, for July 2006 through March 2007. To determine the accuracy of the data the inspectors used definitions and guidance in Revision 5 of the Nuclear Energy Institute (NEI) Document 99-02, "Regulatory Assessment Performance Indicator Guideline." The inspectors reviewed the licensee's operator narrative logs, MSPI derivation reports, issue reports, event reports, and NRC integrated inspection reports for July 1, 2006, to March 31, 2007, to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator; were identified.

This inspection constituted two MSPI emergency AC power system samples.

b. Findings

No findings of significance were identified.

.3 Mitigating Systems Performance Index - High Pressure Injection Systems

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI - High Pressure Injection Systems PIs, for both Units, for July 2006 through March 2007. To determine the accuracy of the PI data the inspectors used definitions and guidance contained in NEI 99-02. The inspectors reviewed the licensee's operator narrative logs, issue reports, MSPI derivation reports, event reports, and NRC integrated inspection reports for July 1, 2006 to March 31, 2007, to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified.

This inspection constituted two MSPI high pressure injection system samples.

b. Findings

No findings of significance were identified.

.4 Mitigating Systems Performance Index - Heat Removal System

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI - Heat Removal System PI, for both Units, for July 2006 through March 2007. To determine the accuracy of the PI data reported during that period, the inspectors used PI definitions and guidance in NEI 99-02. The inspectors reviewed the licensee's operator narrative logs, issue reports, event reports, MSPI derivation reports, and NRC integrated inspection reports for July 1, 2006, to March 31, 2007, to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified.

This inspection constituted two MSPI heat removal system samples.

b. Findings

No findings of significance were identified.

.5 Mitigating Systems Performance Index - Residual Heat Removal System

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI - Residual Heat Removal System PI, for both Units, for July 2006 through March 2007. To determine the accuracy of the PI data reported during that period the inspectors used definitions and guidance in NEI 99-02. The inspectors reviewed the licensee's operator narrative logs, issue reports, MSPI derivation reports, event reports, and NRC integrated inspection reports for July 1, 2006, to March 31, 2007, to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified.

This inspection constituted two MSPI residual heat removal system samples.

b. Findings

No findings of significance were identified.

.6 Mitigating Systems Performance Index - Cooling Water Systems

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI - Cooling Water Systems PI for July 2006 through March 2007. To determine the accuracy of the PI data reported during those periods, the inspectors used definitions and guidance in NEI 99-02. The inspectors reviewed the licensee's operator narrative logs, issue reports, MSPI derivation reports, event reports, and NRC integrated inspection reports for July 1, 2006, to March 31, 2007, to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified.

This inspection constituted two MSPI cooling water system samples.

b. Findings

No findings of significance were identified.

.7 Radiological Effluent TS/Offsite Dose Calculation Manual Radiological Effluent Occurrences

a. Inspection Scope

The inspectors used definitions and guidance contained in Revision 5 of NEI 99-02 to verify the accuracy of the data for the Radiological Effluent Technical Specification/Offsite Dose Calculation Manual (RETS/ODCM) Radiological Effluent Occurrence PI.

The inspectors reviewed the licensee's CAP database and selected individual condition reports generated between December 2006 and November 2007 to identify any potential occurrences such as unmonitored, uncontrolled, or improperly calculated effluent releases that may have impacted offsite dose. The inspectors also selectively reviewed gaseous and liquid effluent summary data and the results of associated offsite dose calculations for selected periods in 2007 to determine if indicator results were accurately reported. The inspectors also discussed with the licensee the methods for quantifying gaseous and liquid effluents and for determining effluent dose.

These reviews represented one inspection sample.

b. Findings

No findings of significance were identified.

4OA2 Problem Identification and Resolution (71152)

.1 Routine Resident Inspector Review

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 whether issues were entered into the licensee's corrective action program at an appropriate threshold, that adequate attention was given to timely corrective actions, and that adverse trends were identified and addressed. The inspectors also reviewed all CAPs written during the inspection period. The CAPs written by the licensee as a result of inspectors' observations are included in the list of documents in the Attachment to this report.

b. Findings

No findings of significance were identified.

.2 Selected Issue Follow-up Inspection: Annual Review of Operator Workarounds

Introduction

The inspectors selected operator workarounds for a more in-depth review in accordance with Inspection Procedure requirements.

This annual review of operator workarounds constituted one inspection sample.

a. Effectiveness of Problem Identification

(1) Inspection Scope

The inspectors reviewed plant logs, condition reports, and work requests to verify that the licensee's identification of operator workarounds was complete, accurate, and timely, and that the consideration of extent of condition review, generic implications, common cause, and previous occurrences was adequate.

(2) Findings and Issues

No findings of significance were identified. No issues were identified.

b. Prioritization and Evaluation of Issues

(1) Inspection Scope

The inspectors reviewed plant logs, condition reports, and work requests associated with existing operator burdens, including operator workarounds, operator challenges, and control room deficiencies. The nature and significance of individual issues and all issues in aggregate with respect to safety, risk, and licensee corrective action procedural requirements were considered. Additionally, the inspectors assessed the licensee's evaluation and disposition of performance issues, evaluation and disposition of operability issues, and application of risk insights for prioritization of issues.

(2) Findings and Issues

No findings of significance were identified. No issues were identified.

c. Effectiveness of Corrective Actions

(1) Inspection Scope

The inspectors reviewed condition reports and work requests associated with existing operator workarounds, operator challenges, and control room deficiencies to determine if the licensee's corrective action program addressed generic implications. Additionally, the inspectors verified that established corrective actions by the licensee were appropriately focused to correct the problem.

(2) Findings and Issues

No findings of significance were identified. No issues were identified.

.3 Semiannual Trend Review

a. Inspection Scope

The inspectors reviewed of the licensee's CAPs and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review was focused on repetitive equipment issues, but also considered the results of daily inspector CAP item screening discussed in Section 4OA2 above, licensee trending efforts, and licensee human performance results. The inspectors' review nominally considered July 2007 through December 2007, although some examples expanded beyond those dates.

The reviews also included issues documented outside the normal corrective action program in major equipment problem lists, repetitive and/or rework maintenance lists, departmental problem/challenges lists, system health reports, quality assurance audit/surveillance reports, self-assessment reports, and Maintenance Rule assessments. The inspectors compared and contrasted their results with the results contained in the licensee's corrective action program trending reports. Corrective actions associated with a sample of the issues identified in the licensee's trending reports were reviewed for adequacy.

This semi-annual trend review by the inspectors constituted one inspection.

b. Findings and Issues.

No findings of significance were identified. No issues were identified.

4OA3 Followup of Events and Notices of Enforcement Discretion (71153)

.1 TS-Required Shutdown Due to High Unit 2 Refueling Water Storage Tank Temperature

a. Inspection Scope

Through record reviews and discussion with plant staff, the inspectors assessed the circumstances of a TS-required shutdown initiated on September 18, 2007. Although the licensee took immediate corrective actions to de-energize the submersion heaters and cool the RWST by forced recirculation, the temperature could not be restored to acceptable limits before the eight-hour TS action statement expired. As a result, Unit 2 commenced a TS-required shutdown that was later averted, while at approximately 20 percent reactor power, when the RWST temperature was restored to within acceptable limits. The inspection scope included a review of the events leading up to the shutdown initiation.

b. Findings

Introduction: A self-revealing finding of very low safety significance (Green) and an associated Non-Cited Violation (NCV) of 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” was identified for the failure to allow operators to properly set the thermostat of the Unit 2 RWST heaters, and to ensure that the RWST was recirculated frequently enough for the temperature indicator to accurately measure bulk temperature.

Description: On September 18, 2007, during the performance of TS-required surveillance SR 3.5.4.1, the Unit 2 RWST was found to be at 105 °F. The TS maximum allowable limit was 100 °F (97 °F parametric). Because RWST temperature could not be restored within the allowed eight hours, operators commenced a shutdown of Unit 2. At 20 percent power, the temperature was returned to within acceptable limits and the operators began to raise reactor power to 100 percent. The cause of the elevated temperature was found to be the incorrectly set RWST heater thermostat.

It was identified that on August 30, the controlling thermostat for the RWST heaters was incorrectly set to 95 °F vice 50 °F as required by procedure. For the 18 days between August 30 and September 18, the bulk water temperature increased to 105 °F through natural circulation. During this period, daily temperature readings of the RWST only showed an increase from 75 °F to 85 °F. This disparity occurred due to stratification caused by the location of the single temperature indicator relative to the heaters inside the tank. Because the RWST temperature indicator is located 2 feet from the bottom of the 70 foot tall tank, and the heaters are located 4.5 feet above the indicator, stratification caused the temperature indicator to remain in a layer of colder water. It was not until September 18, that the RWST temperature was found to be at 105 °F, after four hours of being on forced recirculation.

The inspectors reviewed procedure PC 49, part 4, Revision 19, which was used for setting the thermostat on the RWSTs to 50 °F. This task was performed once a year during cold weather preparations to ensure that the RWST remained within the required temperature range of 40 to 100 °F. Through this review, the inspectors concluded that a lack of sufficient detail existed for the critical step of setting the thermostat, which directly affected the operability of the safety-related RWST. Specifically, the lack of procedural detail contributed to the operator's reliance upon an unapproved operator aid in the field; in this case, a black marking that was believed by the operator to indicate the desired thermostat setting.

The inspectors also reviewed procedure PC 25, Revision 23, which was used to recirculate and purify the RWST. This task was performed to keep the RWST contents in a homogeneous mixture to prevent stratification. Through this review, the inspectors concluded that the frequency of RWST recirculation, which was performed monthly, was inadequate to ensure that the temperature indicator accurately read bulk tank temperature to satisfy the TS operability requirements, while the heaters were energized.

Analysis: The inspectors determined that the failure to have adequate procedures in place to ensure the operability of the safety related RWST is a performance deficiency and a finding. The finding is more than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," dated September 20, 2007, because it is associated with the procedural quality and human performance attributes of the Mitigating Systems Cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

Using IMC 0609, "Significance Determination Process", dated January 10, 2008, the inspectors determined that the finding is of very low safety significance (Green) because the finding did not involve a design deficiency, there was no actual loss of safety function, no single train loss of safety function for greater than the TS allowed outage time, and no risk due to external events. The inspectors also determined that the finding had a cross-cutting aspect in the area of human performance. Specifically, human error prevention techniques were not utilized prior to and during the thermostat setting task and personnel proceeded in the face of uncertainty and unexpected circumstances (H.4(a)).

Enforcement: 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures and drawings. Contrary to this, the licensee's procedure PC 49, part 4, used for setting the RWST heater thermostat, did not have adequate instructions for correctly setting the thermostat. Further, the monthly recirculation of the RWST, specified in procedure PC-25, was not appropriate to ensure that the TS-required temperature readings were valid in their indication of bulk tank temperature while heaters were energized. Because of the very low safety significance of this finding and because the finding was entered into the licensee's corrective action program (CAP 01111841), the violation is being treated as an NCV, consistent with Section VI.A.1 of NRC Enforcement Policy (NCV 05000266/2007005-04; 05000301/2007005-04).

The licensee entered the event into its corrective unit action program, took corrective actions to increase the frequency of the Unit 1 and Unit 2 RWST recirculation to once every seven days until the heaters were no longer needed due to seasonal temperature increases, and conducted a root cause evaluation.

.2 (Closed) Violation (VIO) 05000266/2006011-01; 050000301/2006011-01: Failure to Update Final Safety Analysis Report with Reactor Head Drop Analysis and Obtain NRC Approval

The inspectors evaluated the licensee's corrective action program responses to the January 29, 2007, Notice of Violation associated with the NRC Special Inspection Report 05000266/2006011; 05000301/2006011, for issues in the spring of 2005, regarding a 1982 reactor vessel head drop analysis. The inspectors reviewed the corrective actions the licensee described in its correspondence dated December 19, 2006, entitled, "Response to an Apparent Violation in Inspection Report05000266/2006011; 05000301/2006011; EA-06-274." The inspectors validated the following corrective actions were complete: incorporation of the Reactor Vessel Head Drop Analyses into the FSAR; revision of the Technical Requirements Manual Section 3.9.4; revision of plant procedures, including maintenance, outage, and operations procedures and checklists; development of a licensing basis policy and training for plant staff on that policy; development and implementation of a continuing training module for plant engineers; licensee evaluation and validation of commitments contained in an October 1996 NRC, "Request for Information Pursuant to 10 CFR 50.54(f) Regarding Adequacy and Availability of Design Basis Information," with corresponding corrective actions for identified deficiencies; and development of a procedure writer/reviewer certification matrix with a job familiarization guide which addressed how to search the site's regulatory information system. The review by the inspectors constituted one inspection procedure sample.

4OA5 Other Activities

.1 (Closed) Unresolved Item (URI) 05000266/2007008-06: Inadequate Post-Maintenance Testing (PMT) of the Turbine-Driven Auxiliary Feedwater Pumps Following Major Maintenance

Introduction: The inspectors identified a finding of very low safety significance (Green) and an associated Non-Cited Violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," for the licensee's failure to conduct adequate PMT of the Unit 1 1P-29 TDAFW pump following a ten-year overhaul of the turbine in May 2007. Specifically, the ten-year overhaul maintenance included bearing replacement, but, the PMT did not run the TDAFW pump long enough for bearing temperature to stabilize. The appropriate PMT would have detected that the bearing temperatures were rising and required evaluation prior to declaring the TDAFW operable.

Description: The licensee completed an overhaul of the Unit 1 TDAFW turbine and the associated PMT on May 6, 2007, declaring the TDAFW pump operable following completion of quarterly IST procedure IT-8A. The PMT requirements for the overhaul were listed in the maintenance overhaul procedure, RMP 9044-1. The IST procedure had no specific requirements to monitor bearing temperatures for stabilization other than to perform the IST, which recorded bearing temperature data. The procedure did have a temperature limit to place the pump in the alert range and conduct an engineering evaluation when the turbine outboard bearing exceeded 225 °F, and to remove the pump from service and declare the pump inoperable when the same bearing exceeded 250 °F. However, as part of the PMT for the ten-year overhaul, there was no requirement in either the work order, maintenance procedure or the IST procedure, to ensure bearing temperatures were stabilized.

For testing on May 1, the inspectors noted that the outboard bearing temperature reached 247 °F, as indicated on the chart recorders. During the PMT on May 6, some licensee personnel noted the turbine outboard bearing rising, but indicated the temperatures was "stabilizing." However, the licensee did not wait for temperature stabilization and secured the Unit 1 TDAFW pump. The inspectors' review of chart recorders revealed that the outboard bearing temperature was at 238 °F and still rising. The licensee had declared the TDAFW pump operable with no PMT assessment of the outboard bearing temperature trend and no engineering analysis or evaluation of the changes in outboard bearing temperature from prior to the overhaul.

During the Unit 1 TDAFW pump quarterly IST procedure IT-8A performance on June 9, turbine outboard bearing temperature exceeded 225 °F. The turbine outboard bearing temperature was at 233 °F and still rising when the pump was secured after the test was completed. In this case, a CAP was written and a follow-up test was completed on June 12, with the goal to attain bearing temperature stabilization. The test was stopped at around 249.5 °F, prior to bearing temperature stabilization, and the 250 °F limit to secure the pump. The pump was declared inoperable and the plant was subsequently shutdown to repair the TDAFW turbine.

The licensee's root cause evaluation indicated the turbine was improperly assembled during the overhaul in May 2007. In addition, the inspectors determined that changes to procedure NP 10.2.7, "Post Maintenance/Return to Service Testing," did not occur when a change in the ASME OM Code in 1998 resulted in removing stabilization criteria from the normal ISTs for safety-related equipment. Specifically, the procedure allowed credit to be taken for ISTs; however, the procedure did not alert personnel that ISTs no longer required temperature stabilization. Procedure NP 10.2.7, did specify that licensee personnel review the PMT matrix for maintenance tasks performed, and the PMT matrix specified temperature stabilization for bearing replacements. In addition, the licensee concluded from the root cause that: people interviewed, who were involved with the PMT recommendation, approval, and review process rely on the applicable procedure to be correct and do not verify that the correct PMT is specified in the procedures; many operations, engineering, and planning personnel rely on memory when assigning PMT to work that does not have a procedure-based PMT; and additional training may be necessary for PMT activities.

Past Operability and Availability Analysis

From July through December 2007, the licensee evaluated the past operability and availability of the Unit 1 TDAFW pump. The inspectors, in conjunction with a technical matter expert from the Office of Nuclear Reactor Regulation and a Regional Senior Reactor Analyst, reviewed the licensee's past availability analysis, and verified the assumptions, calculations, and conclusions made by the licensee in AR 01090456, "Past Availability 1P-29 Turbine Driven Auxiliary Feedwater Pump." The inspectors verified the conclusion made by the licensee that the as-found condition of the turbine would have resulted in the turbine being able to perform its function for the 24-hour mission time. The as-found condition consisted of the following known deficiencies caused by the spring 2007 maintenance: inadequate wheel lap setting, inadequate pump-to-turbine coupling stretch; inadequate stretch and misalignment in the gear box coupling; and inadequate thrust bearing axial end clearance. The basis for concluding that the TDAFW pump would have performed its function were as follows: the accumulated run time without component degradation provided indications of satisfactory operation of components other than the bearing; the vibration measurements of the turbine and pump were satisfactory and indicated normal operation; oil analysis for the bearings were acceptable; IST data for the pump indicated no appreciable difference between the results prior to and after the overhaul of the turbine; outboard bearing temperatures, while significantly higher than normal, were determined via analysis by a vendor and concurrence by the turbine manufacturer to stabilize at a temperature that was acceptable for a 24-hour mission time; analysis demonstrated that adjacent turbine components would not be affected by the increased bearing temperature; analysis of the oil at increased temperatures by the oil vendor demonstrated no significant decrease in oil properties; and the increased bearing temperatures were evaluated by the bearing manufacturer and determined not to affect the operation of the bearing for a 24-hour mission time.

Analysis: The inspectors determined the failure to have adequate PMT of the TDAFW pumps was a performance deficiency and a finding. Using IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," dated September 20, 2007, the inspectors determined that this finding is more than minor because if left uncorrected, the failure would become a more significant issue.

Using IMC 0609, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations," Attachment 1, "SDP Phase 1 Screening Worksheet for IE, MS, and B Cornerstones," dated January 10, 2008, the inspectors determined that the finding did not result in an actual loss of safety function of a system or train of equipment. Therefore, the finding is considered to be of very low safety significance (Green). The inspectors also determined that this finding had a cross-cutting aspect in the area of human performance because the licensee did not ensure that procedures were adequate and accurate to assure nuclear safety (H.2(c)).

Enforcement: 10 CFR 50, Appendix B, Criterion V, requires, in part, that activities affecting quality be prescribed and accomplished by procedures appropriate to the circumstances. Contrary to this, the licensee failed to prescribe and accomplish adequate PMT with procedures appropriate to the circumstances to ensure that after maintenance on safety-related equipment, the equipment returned to service in an operable condition, an activity affecting quality. Because this finding was of very low safety significance (Green) and because the finding was entered into the licensee's corrective action program (as CAP 01090456), this violation is being treated as a Non-Cited Violation (NCV 05000266/2007005-05; NCV 05000301/2007005-05), consistent with Section VI.A of the NRC Enforcement Policy.

The licensee took immediate corrective actions to address the issue by revising the appropriate procedures, and at the end of the inspection period the licensee continued to implement planned corrective actions.

.2 <u>Evaluation of Licensee's Organizational Response to the 2P-29 TDAFW Pump Emergent Issue</u> (95003)

b. <u>Inspection Scope</u>

The inspectors utilized additional inspection hours allowed by IMC 0305 "Operating Reactor Assessment Program," since Point Beach exited Column IV of the NRC's Action Matrix in 2007, to assess the licensee's organizational response to a significant issue associated with the Unit 2 2P-29 TDAFW pump in November 2007. In particular, the inspectors focused on the organizational use of human performance tools, the performance of operations and engineering personnel during the issue, and utilization of the corrective action program by the organization.

Increased water in the outboard bearing of TDAFW pump 2P-29 was first observed in June 2007. The licensee performed an operability evaluation at that time and concluded that the pump was operable because the concentration of the oil was below the 5,000 pm threshold value for operability established by the licensee, based on Electric Power Research Institute (EPRI) and vendor guidance. Test results revealed in June 2007 that the water concentration was approximately 140 ppm and in July compensatory testing identified an increase to 760 ppm. The licensee continued to trend increasing water in the oil and developed a contingency plan. On September 21, the oil sample results revealed water levels had increased to 3,845 ppm, and during the 2P-29 TDAFW pump run, an outboard high temperature alarm occurred. In addition, operators noted that additional leakage was observed from the turbine outboard gland area. The licensee commenced implementation of the contingency plan, which included a pump overhaul.

The overhaul was completed on September 23, and included replacement of the turbine shaft carbon seal rings and the turbine outboard gland seal casing. The gland and turbine casings were then sealed with high temperature silicone per the maintenance procedure. The TDAFW pump was run and oil samples were collected. The water content was visually estimated at 1,500 ppm, and the licensee concluded that they were within the bounds of the previous operability evaluation. A second test run conducted that day revealed less water visually than the first run. Both samples were sent offsite for analysis. On September 27, the lab results were received, with the first run showing 20,400 ppm of water and the second run showing only 56 ppm of water. Condition report CAP 01113318 was written; however, the description discounted the higher sample based on conformational biases of the personnel involved, specifically: high room humidity; statements from a vendor representative noting that increased leakage may be expected following overhauls (even though this had never been seen on the identical turbine for the opposite unit); and high humidity in the room where the samples were split for offsite analysis. Consequently, CAP 01113318 was closed with no action taken.

On November 1, 2P-29 was run twice and the water content in the oil was analyzed at 29,515 ppm for the first run and 17,700 ppm for the second run, supporting the September 2007 value of 20,400 ppm of water as a valid result. The licensee subsequently initiated its event response procedure. Revision 2 of operability Evaluation OPR01098358 was performed and completed on November 3, and required a compensatory measure of running the turbine and sampling the oil every 72 hours. Over the next several days, the TDAFW pump was run for eight hours, every 72 hours.

Additional data and responses by the licensee to the inspectors questions necessitated three additional revisions of the OPR by November 10. On November 13, due to the continued high water content, the licensee elected to overhaul the turbine. The licensee, with vendor assistance, identified the following significant as-found conditions during the overhaul: a gap in the aluminum oil deflector ring attached to the turbine shaft by a set screw, that provided a direct path for steam to enter the bearing housing along the turbine shaft; the silicone sealant, particularly around the gland housing and casing, exhibited a lack of adhesion, also providing a path for steam entering; and the gland housing, which was replaced in the September 2007 maintenance, was undersized. Following the November 2007 overhaul, the pump underwent PMT and the outboard bearing oil samples showed less than 100 ppm of water.

c. Findings

The inspectors identified three Green findings with associated NCVs as a result of the inspection activities. Two findings are documented in this Section and a third is documented in Section 1R15.2 of this report.

b.1 Failure to Take Adequate Corrective Actions to Address Water Ingress Following Maintenance

Introduction: The inspectors identified a Non-Cited Violation (NCV) of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," having very low safety significance (Green) for the licensee's failure to take prompt corrective actions to correct the cause of increased water in the 2P-29 TDAFW pump turbine outboard bearing housing, a condition adverse to quality, originally identified in September 2007.

Description: On September 24, 2007, following the overhaul of the 2P-29 TDAFW pump turbine, an oil sample was taken from the outboard bearing housing, following a four hour run. CAP 01112660 was written, which documented water volume in the oil sample of 1,000 to 1,500 ppm for the four-hour run. The CAP description concluded that this was an expected condition. A second shorter pump run was performed, and the water content in the oil was visually estimated to be 100 ppm. The licensee rationalized that the initial water content was expected and the CAP was closed with no further actions taken. Three days later, CAP 01113318 was written and documented that the outboard oil sample from the first four-hour run was actually 20,040 ppm water, and that the number was not consistent with the visual indications seen on September 24. The description in the CAP was presented in a manner which refuted the results based on conjecture, concluding that the 20,040 ppm results were false readings due to a laboratory error or an accidental capture of water droplets during the sampling process. The CAP concluded that, "the indicated levels of water in the IT-09A sample are errant." The CAP was screened by licensee staff and no additional actions were taken to either characterize the cause of the unexplained increase of water in the oil, or to further evaluate this unexpected condition identified through testing of the safety-related oil, following the four-hour TDAFW pump run. The licensee did not consider as a corrective action, running the pump and obtaining another oil sample to verify that the abnormally high water content following the overhaul was a false indication.

On November 1, approximately five weeks after the maintenance overhaul, the licensee ran 2P-29 and sampled the oil. The frequency of running the pump once per month was established in June 2007, when the moisture in the turbine outboard bearing oil was significantly less than the EPRI and vendor recommended 5,000 ppm. The pump was run slightly more than two hours and the outboard oil sample drawn revealed 29,515 ppm of water in the oil. After the pump had not run for about eight hours and was then run for eight hours, 17,700 ppm was found in the outboard bearing oil. The licensee declared the pump inoperable and revised the original June 2007 operability evaluation. As described previously, on November 13, the licensee began an overhaul of the turbine.

The inspectors determined that the original unsatisfactory oil sample results in September 2007 identified a condition adverse to quality associated with the safety-related 2P-29 TDAFW pump; however, prompt corrective actions were not taken.

Analysis: The inspectors determined that the licensee's failure to implement prompt corrective actions to address the September 2007 2P-29 TDAFW pump turbine degraded oil sample results, a condition adverse to quality, was a performance deficiency and a finding. The inspectors concluded that the finding is more than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," dated September 20, 2007, in that the finding could reasonably be viewed as a precursor to a significant event. Specifically, the failure to promptly correct the cause of the oil degradation in a timely manner could result in failure of the TDAFW turbine.

The significance of this finding was evaluated using IMC 0609, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations," dated January 10, 2008, for the Mitigating Systems Cornerstone. The risk assessment for the potential loss of safety function is attributed to the performance deficiencies associated with inadequate maintenance discussed in Section 4OA5.2.b.2 as URI 5000266/2007005-07. This finding, for the failure to implement prompt corrective actions, did not cause the loss of safety function for greater than the allowed outage time. The inspectors determined that the finding is of very low safety significance (Green), because the finding did not involve a design deficiency, there was no actual loss of safety function, no single train loss of safety function for greater than the TS allowed outage time, and no risk due to external events. The licensee concluded that although the pump was initially declared inoperable and the oil was degraded, the TDAFW pump would have performed its specified safety function. Additionally, the inspectors determined that the finding had a cross-cutting area aspect in the area of problem identification and resolution. Specifically, the licensee failed to thoroughly evaluate the problem with water ingress into the oil, such that a resolution addressed the cause and extent of condition (P.1(c)).

Enforcement: 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," requires, in part, that measures be established to assure that conditions adverse to quality, such as malfunctions, deficiencies, deviations, defective equipment and nonconformances are promptly identified and corrected. Contrary to this, a condition adverse to quality, associated with the turbine of the Unit 2 TDAFW pump 2P-29 was not promptly corrected following identification in September 2007. Specifically, upon identification of degraded oil in September 2007, a condition adverse to quality, the licensee did not take prompt corrective actions. As a result of the failure to take prompt corrective actions, the pump was declared inoperable until November 2007, following additional oil samples that revealed the continued degraded condition. Because of the very low safety significance of this finding and because it was entered into the licensee's corrective action program as CAP 01115748, this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 05000301/2007005-06).

The licensee took immediate corrective actions to address the issue, which included reevaluation of operability and ultimately overhaul of 2P-29, and at the end of the inspection period the licensee continued to evaluate the causes associated with this finding.

b.2 Unresolved Item: Failure to Perform Adequate Maintenance Resulting in Increased Water Ingress

Introduction: The inspectors identified a URI associated with the licensee's failure to perform adequate maintenance on the Unit 2 TDAFW pump turbine in September 2007.

Description: The elevated moisture content in the outboard bearing for the 2P-29 turbine was present since the last ten-year overhaul was performed in November 2006. However, while the moisture content levels in the oil from November 2006 until the September 21, 2007, overhaul were elevated, the levels were below the 5,000 ppm value documented as acceptable in EPRI and vendor guidance. Steam leakage from the gland seal or turbine casing joints prior to the September overhaul would not have been vented away from the bearing housing since the turbine insulation extended over the top of the gland seal casing and up to the bearing housing. In addition, original cement-based insulation also blocked the gland seal area vent holes.

The licensee concluded, based on test data, that the 2P-29 turbine overhaul that was completed on September 23, 2007, significantly increased the moisture content in the outboard bearing oil. A silicone seal applied at the gland casing to turbine casing joint failed upon initial service resulting in a steam leak in the area of the outboard bearing housing. The failure of the sealant could not be attributed to one factor; however, the licensee did conclude one of the root causes was its maintenance procedures did not address the special requirements needed when applying sealants, and, therefore, site personnel did not have adequate instruction or training on the use of sealants. In addition, the licensee identified that the September 2007 maintenance did not allow for the proper cure time of 24 hours for the sealant and exceeded the process time of 30 minutes from when the sealant was applied and the joint was torqued.

In a review of the site maintenance procedures, the licensee also identified an additional root cause that the site continued to lack adequate guidance on specific assembly details of the turbine, specifically for the oil deflector ring on the turbine shaft: the tightening of the oil deflector ring set screw was not discussed; and acceptable clearances between the turbine shaft and the inner diameter of the oil deflector ring were not specified.

The licensee identified three additional contributing causes: receipt and installation of a gland casing from the vendor that had incorrect critical dimensions; previous insulation work blocked the gland seal vents; and plant personnel did not have adequate guidance on the installation of insulation. At the end of the inspection period, the licensee continued to develop and implement corrective actions to address the issues documented in CAP 01115748.

At the conclusion of the inspection, the licensee continued to assess the impact of the water ingress on the availability of the Unit 2 TDAFW pump to perform its design and augmented quality functions. There is no current safety concern because the pump was adequately tested and the current low ingress of water into the bearing housing indicated that the pump's functionality is currently maintained for all licensing and design basis events. This issue is an Unresolved Item (URI 05000301/2007005-07) until the NRC reviews the licensee's past availability assessment.

.3 Evaluation of the Licensee's Independent Assessment of Engineering (95003)

a. Inspection Scope

The inspectors utilized additional inspection hours allowed by IMC 0305, since Point Beach exited Column IV of the NRC's Action Matrix in 2007, to assess the licensee's independent assessment of engineering. The licensee committed as part of its response to the Confirmatory Action Letter CAL 3-04-001, Revision 1, dated April 14, 2006, to perform alternating independent and self-assessments of the engineering and corrective action programs. In July 2007, the licensee performed an independent assessment of engineering performance. The inspectors reviewed the charter for the assessment, observed the independent assessment team, reviewed the final report, and reviewed the proposed corrective actions.

b. Observations and Assessment

The team consisted of four experienced individuals from other utilities and a consulting firm. The team assessed licensee engineering performance in five areas: fundamentals of engineering, equipment reliability, configuration management, corrective actions, and operating experience. The assessment team's overall conclusions were: engineering rigor and overall quality has improved and has been sufficient for successful management of potential challenges to design bases and equipment reliability; unresolved plant material conditions present substantial ongoing challenges; a plateau may have been reached for engineering improvement; and additional resources and continued effort will be required to sustain the improvements that have already been obtained and to bridge the remaining gaps to engineering excellence.

The assessment team identified the following overall issues for attention: most recent engineering products are of high quality, but examples of products with less than adequate rigor are still produced; engineering needs to be more predictable and accountable with respect to schedules; important longstanding issues were not resolved; engineering resources may not be adequately matched to engineering obligations; the preventive maintenance optimization and single point vulnerability projects have languished and, as a consequence, the station had not benefited from the improved material condition and safety margins; although a list of low margin issues had been established, there did not appear to be a quantification of the lost margin associated with these issues or an evaluation of the cumulative effects; it was not clear that cumulative effects of conditions adverse to quality were being addressed and the large number of open conditions presented a challenge to effectiveness of such a review; and the corrective action process was not used to the full potential, specifically: trending was not being used as effectively as it could be; more effective use of corrective action processes for vendor products was warranted; and expectations for a close to fix solution, versus an apparent cause evaluation warranted examination.

The overall recommendations from the assessment team were 1) to maintain highly visible management commitment to rigor and continue associated empowerment, and 2) to implement the specifically identified corrective actions for issues with predictability, resolution of longstanding issues, prevent maintenance optimization, cumulative effects of material condition, more aggressive use of corrective action processes, margin issues, and engineering resources.

The inspectors confirmed that the licensee had developed plans and corrective actions to address the issues for attention identified by the Independent Assessment Team.

.4 Evaluation of the Independent Assessment of the Corrective Action Program (95003)

a. Inspection Scope

The inspectors utilized additional inspection hours allowed by IMC 0305, since Point Beach exited Column IV of the NRC's Action Matrix in 2007, to assess the licensee's independent assessment of the corrective action program. The licensee committed as part of its response to the Confirmatory Action Letter CAL 3-04-001, Revision 1, dated April 14, 2006, to perform alternating independent and self-assessments of the engineering and corrective action programs. The inspectors reviewed the charter for the assessment of the corrective action program in August 2007, observed the independent assessment team, reviewed the final report, and reviewed the proposed corrective actions.

b. Observations and Assessment

The team consisted of four experienced individuals from other utilities and a consulting firm. The team concluded that although measurable improvement in the corrective action program had been achieved over the last 12 months, several opportunities for improvement needed to be addressed in order to achieve improved performance. The team noted the following opportunities for improvement: the effectiveness and quality of apparent cause evaluations needed to be improved; the number of corrective action program performance indicators above target with no detailed recovery plan indicated that timeliness continued to be an issue, corrective action program backlog, in particular, has been increasing; the ease of CAP initiation via computer (Passport software) and providing feedback to the CAP initiator for CAPs which are closed by the management screening committee with no action; trending has not been effective at identifying adverse trends through the quarterly Department Roll-Up Meetings and Passport issues continue to impede trending; effectiveness reviews for corrective actions to prevent recurrence needed to consider effectiveness from a broader perspective; additional opportunities for improvement were identified in apparent cause evaluations for NRC-identified findings and on the effectiveness of certain actions specified to correct the January 2007 corrective action program self-assessment issues.

The independent assessment team concluded that some positive features of the corrective action program included: management was highly engaged in the program and the screening committee appears to be highly effective; root cause evaluations were thorough and comprehensive, and effectiveness review criteria were clearly specified; format consistency has improved for apparent cause evaluations, effectiveness reviews, and department roll-up meeting reports; the Performance Assessment Review Board was involved in reviewing the backlog of open CAPs by department; and most actions taken to address issues from the January 2007 corrective action program self-assessment had resulted in measurable improvement.

The inspectors confirmed that the licensee had developed plans and corrective actions to address the opportunities for improvement identified by the Independent Assessment Team.

.5 (Closed) URI 05000266/2006004-05; 05000301/2006004-05: Inadequate 10 CFR 72.48 Screening to Evaluate Possible Thermal Effects on Fuel Cladding

Introduction: The inspectors identified one violation of 10 CFR 72.48(c)(1) in which the licensee failed to obtain a Certificate of Compliance (CoC) amendment pursuant to 10 CFR 72.244 for changes made in the spent fuel storage cask operating procedures during the 2004 loading campaign as described in the FSAR and these changes in the procedures constituted a change in the terms, conditions, or specifications incorporated in the CoC. Specifically, although Point Beach changed an operating procedure described in the FSAR that allowed pump down of water from the dry shielded canister to occur much earlier in the process; Point Beach failed to identify that the following TS, which was incorporated in the CoC, would have required changes that needed prior NRC approval: TS 1.2.17a, "32PT Dry Storage Canister (DSC) Vacuum Drying Duration Limit."

Description: During the fall 2004 campaign, the licensee used the new NUHOMS 32-PT cask design and modified the sequence of its loading procedures from the generic operating procedures stated in Chapter M.8 of the FSAR. The change consisted of draining all of the water from the canister cavity prior to welding the inner top cover on, whereas the FSAR prescribed draining some of the water from the canister (approximately 750 gallons), then welding the top inner cover and then draining the remainder of the water from the canister. In the 10 CFR 72.48 screening, the licensee failed to evaluate the effect of the water removal during draining and welding on the fuel cladding temperature. The inadequate screening failed to identify that TS 1.2.17a, "32 PT DSC Vacuum Drying Duration Limit," which was incorporated in the CoC, would have required a change that needed prior NRC approval. This amendment to the CoC would address any affects on the vacuum drying time limits that may result from the potentially higher fuel cladding temperature. The initial fuel cladding temperature, at the start of vacuum drying in the procedure that deviated from the FSAR, could be higher than the FSAR assumed value of 215 °F. An assumed temperature of the fuel cladding higher than the 215 °F basis in the FSAR may result in a shorter vacuum drying time than that specified in TS 1.2.17a. The licensee loaded five casks utilizing the different loading process.

Subsequently, in 2006, the licensee's cask vendor, Transnuclear, performed a NUHOMS 32PT drain down evaluation (Calculation No. NU32PT-0420) to address the issues with the vacuum drying duration limit and fuel cladding temperature. The inspectors reviewed the calculation, which concluded that the maximum fuel cladding temperature for the 32PT DSC with a heat load of 16.88 kilowatts (kW) (highest heat load for the 32PT DSC amongst users of this canister at the time) was 720 °F. The 720 °F temperature was below the allowable limit of 752 °F. Therefore, no time limitation was necessary for vacuum drying of the 32PT DSC when the total decay heat load was 16.88 kW or below.

Transnuclear also performed another evaluation (Calculation NUH32PT-0421) in which it modeled a loading configuration that resulted in the maximum fuel cladding temperature for vacuum drying. This loading configuration produced a 22.4 kW total heat load. TS 1.2.17a stated that the limit for duration of vacuum drying was 31 hours for a 32PT DSC with a heat load greater than 8.4 kW and up to 24 kW after initiation of vacuum drying. This value of 22.4 kW total maximum heat load was within the maximum TS fuel cladding temperature for the 24 kW heat load. The results of this evaluation justified using a constant temperature of 215 °F for DSC during handling, welding, and vacuum drying operations, and indicated that after 31 hours of vacuum drying the maximum fuel cladding temperature was 739 °F, below the allowable limit of 752 °F. The maximum fuel cladding temperature reached the allowable limit of 752 °F at 67 hours after the start of the DSC drainage. Thus, the evaluation concluded that the time limit of 31 hours for vacuum drying was acceptable.

<u>Analysis</u>: The inspectors determined that the failure to obtain a CoC amendment pursuant to 10 CFR 72.244 for changes made in the spent fuel storage cask operating procedures, as described in the FSAR, was a performance deficiency and a finding. This finding is more than minor because it had the potential to impact the NRC's ability to perform its regulatory function, since the licensee failed to receive NRC approval for a change in this licensed activity. A CoC amendment was required since these changes in the procedures constituted a change in the terms, conditions, or specifications incorporated into the CoC. The inspectors determined that the finding was not suitable for SDP evaluation because the noncompliance involved 10 CFR Part 72 dry fuel storage activities. Therefore, this finding was reviewed by Regional Management and dispositioned using traditional enforcement.

<u>Enforcement</u>: 10 CFR 72.48(c)(1) states, in part, that a certificate holder may make changes in the facility or spent fuel storage cask design as described in the FSAR (as updated), make changes in the procedures as described in the FSAR (as updated), without obtaining: (a) a Certificate of Compliance (CoC) amendment submitted by the certificate holder pursuant to 10 CFR 72.244; if: (b) a change in the terms conditions, or specifications incorporated in the CoC is not required; and (c) the change, test, or experiment does not meet any of the criteria in paragraph in 10 CFR 72.48(c)(2).

Contrary to this, in an approved 10 CFR 72.48 evaluation, Point Beach failed to obtain a CoC amendment pursuant to 10 CFR 72.244 for changes made in the spent fuel storage cask operating procedures as described in the FSAR (as updated) and these changes in the procedures constituted a change in the terms, conditions, or specifications incorporated in the CoC. Specifically, although Point Beach changed an operating procedure described in the FSAR which allowed pump down of water from the dry shielded canister to occur much earlier in the process; Point Beach failed to identify that the following TS, which was incorporated in the CoC, would have required changes that needed prior NRC approval: TS 1.2.17a, "32PT DSC Vacuum Drying Duration Limit." Because this violation was of very low safety significance, was not repetitive or willful, and was entered into your corrective action program, this violation is being treated as an NCV of 10 CFR 72.48(c)(1), consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 05000266/2007005-09; 05000301/2007005-09).

The licensee entered the issue into the corrective action program as CAP 01026070 and implemented corrective actions, including revising the loading procedure to reflect the sequence described in the FSAR prior to loading the next cask (cask 6).

.6 (Closed) URI 07200005/2004003-01: Adequacy of Design Calculation, PBNP-305336-SO1

During an October through December 2004 NRC inspection, inspectors identified one URI associated with the adequacy of the licensee's auxiliary building structure and the crane design basis during a seismic event. The licensee received an NCV of 10 CFR 72.122(2)(i), documented in Inspection Report 07200005/2004-003(DNMS), regarding failure to demonstrate that the crane, a component important to safety, was designed to withstand the effects of an earthquake without impairing its capability to perform its intended function. Upon further review, the inspectors identified other deficiencies in the structural analysis of the building and the crane for which the URI was opened. There was no response spectra analysis performed on the building to model its response due to an earthquake at different elevations, such as that of the crane. Also, the inspectors could not independently verify that the basis for the horizontal accelerations in all of the calculations used for the auxiliary building and the crane were adequate. In response to these questions, the licensee constructed a detailed computer model of the steel portion of the auxiliary building. The preliminary results from an analysis using this model demonstrated that the original acceleration values were conservative and adequate to demonstrate compliance with regulations and the ability of the building and the crane to sustain up to a 125-ton load under an earthquake scenario. In addition, the licensee hired an independent consultant who confirmed the licensee's results. The inspectors were not able to validate these conclusions since the appropriate documentation was not available at the time of the inspection and a complete analysis was not completed. However, the licensee committed to perform a full analysis of the auxiliary building and the crane response under a seismic event with the current plant conditions.

The licensee performed an analysis of the Class 3 Primary Auxiliary Building (PAB) Steel Superstructure in Calculation PBNP-305336-SO1, "Structural Analysis of Central PAB with Crane Load of 125 Tons," Revision 1, dated April 3, 2006. During the current inspection, NRC staff reviewed the calculation results and discussed the assumptions with licensee personnel. The analysis demonstrated the capability of the structure to support the crane with a load of 125 tons in case of a seismic event once the welded connection of the gusset and Columns 10U and 13U were strengthened. Thus, the calculation verified that the requirements of NUREG-0612 and 10 CFR 72.122(b)(2)(i) were satisfied. The inspectors concluded that the revised calculation was adequate to demonstrate compliance with regulations and the ability of the building and the crane to sustain up to a 125-ton load under an earthquake scenario.

4OA6 MANAGEMENT MEETINGS

.1 Exit Meeting Summary

On January 10, 2008, the inspectors presented the inspection results to Mr. James McCarthy and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

.2 Interim Exit Meeting

An interim exit meeting was conducted for:

- Maintenance Effectiveness Periodic Evaluation with Mr. Walt Smith, Acting Plant Manager on November 2, 2007.
- Biennial Licensed Operator Requalification Program Inspection with Mr. J. McCarthy on November 9, 2007.
- Overall assessments of the annual operating test via telephone with Mr. C. Sizemore on November 21, 2007.
- Emergency Preparedness inspection with Ms. Ray and Mr. Tulley on December 13, 2007.
- Occupational radiation safety cornerstone radiation monitoring instrumentation and protective equipment with Messrs. J. McCarthy and G. Packard and other licensee staff on December 14, 2007.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

R. Amundson, General Supervisor Operations Supervisor
C. Butcher, Site Engineering Director
G. Casadonte, Fire Protection Coordinator
W. Godes, Training Supervisor
R. Harrsch, Operations Manager
M. Hayes, Radiation Protection Supervisor
C. Jilek, Site Maintenance Rule Coordinator
J. McCarthy, Site Vice-President
G. Packard, Plant Manager
S. Pfaff, Performance Assessment Supervisor
K. Phillips, Outage Manager
M. Ray, Regulatory Affairs Manager
C. Sizemore, Training Manager
T. Schmitt, Lead health Physics Technician
S. Tulley, Emergency Preparedness Manager
B. Vandervelde, Maintenance Manager
D. Villicana, Radiation Protection General Supervisor
G. Young, Nuclear Oversight Manager

Nuclear Regulatory Commission

M. Kunowski, Chief, Reactor Projects, Branch 5

J. Cushing, Point Beach Project Manager, Office of Nuclear Reactor Regulation

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened and Closed

05000266/2007005-01; 05000301/2007005-01	FIN	Failure to Control Loose Materials Classified as Tornado Hazards (Section 1R01.1)
05000266/2007005-02; 05000301/2007005-02	FIN	Failure to Adequately Assess Operability of Service Water Pump P-32C (Section 1R15.1)
05000301/2007005-03	NCV	Failure to Perform Operability Evaluations for Turbine-Driven Auxiliary Feedwater Pump 2P-29 (Section 1R15.2)
05000266/2007005-04; 05000301/2007005-04	NCV	Failure to Have Adequate Procedures for the Refueling Water Storage Tank (Section 4OA3.1)
05000266/2007005-05; 05000301/2007005-05	NCV	Failure to Perform Adequate Post-Maintenance Testing for the Turbine-Driven Auxiliary Feedwater Pumps (Section 4OA5.1)

05000301/2007005-06	NCV	Failure to Adequately Evaluate a Condition Adverse to Quality Associated with Turbine-Driven Auxiliary Feedwater Pump 2P-29 (Section 4OA5.2.b.1)
05000266/2007005-08; 05000301/2007005-08	NCV	Failure to Provide Adequate Guidance to Ensure the Operability of the MS System During a Steam Generator Tube Rupture. This Item was described in NRC Inspection Report 2007301, dated August 21, 2007, as Item Numbers 05000266/2007301-01 and 05000301/2007301-01; however, this item is being repeated in this table for NRC Plant Issues Matrix tracking.
05000266/2007005-09; 05000301/2007005-09	NCV	Inadequate 10 CFR 72.48 Screening to Evaluate Possible Thermal Effects on Fuel Cladding (Section 4OA5.5)

<u>Opened</u>

05000301/2007005-07	URI	September 2007 Maintenance Activities Associated with Turbine-Driven Auxiliary Feedwater Pump 2P-29 (Section 4OA5.2.b.2)

<u>Closed</u>

05000266/2006011-01; 05000301/2006011-01	VIO	Failure to Update Final Safety Analysis Report with Reactor Head Drop Analysis and Obtain NRC Approval (Section 4OA3.2)
05000266/2006004-05; 05000301/2006004-05	URI	Inadequate 10 CFR 72.48 Screening to Evaluate Possible Thermal Effects on Fuel Cladding (Section 4OA5.5)
07200005/2004003-01	URI	Adequacy of Design Calculation, PBNP-305336-SO1 (Section 4OA5.6)

LIST OF DOCUMENTS REVIEWED

The following is a partial list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspector reviewed the documents in their entirety, but rather that selected sections or portions of the documents were evaluated as part of the overall inspection effort. Inclusion of a document on this list does not imply NRC acceptance of the document or any part of it, unless this is stated in the body of the inspection report.

1R01 Adverse Weather Protection

Issue Reports:
- CAP 01114731; Loose Materials Found in the Protected Area; October 19, 2007
- CAP 01114637; Material in Yard; 10/18/2007
- CAP 01094135; Tornado Hazards Identified Performing PC 99; May 25, 2007
- CAP 01102551; Tornado Hazards Identified Performing PC-99; July 19, 2007
- CAP 01112508; Tornado hazards Identified Performing PC-99; September 21, 2007
- CAP 01098214; 3 or More Tornado Hazards in Single Inspection. Area; June 21, 2007

Procedures:
- PC 99; Tornado Hazards Inspection Checklist; Revision 0
- AOP-13C; Severe Weather Conditions; Revision 17
- NP 1.9.6; Plant Cleanliness and Storage; Revision 22

1R04 Equipment Alignment

- CL 11A G01; G01 Emergency Diesel Generator Checklist; Revision 22
- CL 11A G02; G02 Emergency Diesel Generator Checklist; Revision 26
- CL 13, Part 1; Auxiliary Feedwater Lineup Unit 1 Turbine Driven; Revision 36
- CL 13, Part 1; Auxiliary Feedwater Lineup Unit 2 Turbine Driven; Revision 40
- CL 13, Part 1; Auxiliary Feedwater Lineup Motor Driven; Revision 42
- O-SOP-G01-001; Maintenance Operation for Emergency Diesel Generator G01; Revision 5
- O-SOP-G01-002; Maintenance Operation for Emergency Diesel Generator G02; Revision 8
- O-TS-AFW-002; Auxiliary Feedwater System Valve and Lock Checklist – Monthly; Revision 10

1R05 Fire Protection

Fire Hazards Analysis Report; January 2007 Revision

1R07 Heat Sink Performance

Documents:
- Bio/Silt Fouling Inspection Form for EDG G01 Heat Exchanger; November 2007
- Bio/Silt Fouling Inspection Form for EDG G02 Heat Exchanger; December 2007

1R11 Licensed Operator Requalification Program

Issued Reports:
- Point Beach ROP Plant Issue Matrix from 09/01/2005 to 10/11/2007; October 11, 2007
- Point Beach Nuclear Plant, Units 1 and 2 NRC Integrated Inspection Reports; dated various from October 26, 2005, through October 26, 2007

- LER 266/2005-007-00; Control Rod Movement With Refueling Cavity Water Level Below TS 3.9.6 Limit; January 16, 2006
- Nuclear Oversight Assessment Reports for Point Beach; dated various 2006 and 2007
- Operations Training Advisory Committee Meeting Minutes; dated various from March 15, 2006, through September 13, 2007
- LOR Curriculum Review Committee Meeting Minutes; dated various from March 7, 2006, through September 28, 2007
- AO Curriculum Review Committee Meeting Minutes; February 21, 2007
- Completed TRQM 19.32; Activation of an Inactive SRO License; Two Separate Forms; February 24, 2006, and June 5, 2006
- Completed PBF-2094; NRC License Active Status Tracking; dated various
- Completed PBF-6097; Operations Watchstander Temporary Restriction Form; dated various
- Licensed Operator Quarterly Status Report; dated various
- Operations Continuing Training End of Cycle Reports; dated various 2006 and 2007
- QF-1050-01a; Course/Cycle Feedback Summary Form; dated various 2006 and 2007
- 2007 – 2008 LOR Biennial Training Plan (BTP); Revision 3
- 2006 NRC Biennial Written Exams; dated various
- Point Beach Nuclear Plant 2005/2006 Biennial Written Exam Summary
- Point Beach Nuclear Plant 2005/2006 Biennial Written Exam Test Item Statistics
- Point Beach Nuclear Plant 2005/2006 Biennial Written Exam Sample Plan
- Evaluation ID# PB-LOR-006-001E; Written Exam Item Review; August 6, 2007
- Management Observations of Training 2006 and 2007
- Licensee 71111.11 Pre-Inspection; August 13, 2007
- LOR Cycle Attendance Sheets; dated various
- Completed QF-1040-04; Remediation Training Form; dated various
- Completed QF-1040-15; Self-Study/Make-Up Training Form; dated various
- Completed QF-1073-01; Walkthrough Exam Summary; Exam Weeks 5 and 6 of 2007; dated various
- Completed QF-1073-02; Crew Simulator Evaluation Summary; Exam Weeks 5 and 6 of 2007; dated various
- Completed QF-1073-03; Individual Operator Simulator Examination Summary; Exam Weeks 5 and 6 of 2007; dated various
- Completed QF-1073-04; Remediation Training Form; Exam Weeks 5 and 6 of 2007; dated various
- Simulator Review Committee Meeting Minutes; dated various from March 2, 2006, through September 13, 2007
- FP-T-SAT-81; Simulator Testing and Documentation; Revision 4
- SWO 05-0039; Rehost Simulator PPCS, March 22, 2005
- SIMGL C1.4; Install and Test U1C31; November 2, 2007
- SIMGL C3.3; Simulator Certification Testing; September 21, 2005
- SCT 6.8.37.5; Stuck Open Condenser Dump Valve; August 29, 2006
- SCT 6.3.2; 75 Percent Power Heat Balance; July 12, 2006
- SCT 6.1.4; 100 Percent Steady State Drift Test; July 11, 2006
- SCT 6.8.13.3; Loss of a 4160 Volt Bus; December 7, 2006
- SCT 6.8.16.3; Generator Inadvertent Trip; July 18, 2006
- SCT 6.5.1; Manual Reactor Trip; April 3, 2006
- SCT 6.5.8; Loss of Coolant Accident With Loss of Offsite Power; March 30, 2006
- Simulator Review Committee Meeting Minutes; June 28, 2007
- Simulator Review Committee Meeting Minutes; February 12, 2007
- Simulator Work Orders Closed Out in Previous 12 Months; November 1, 2007
- List of Open Simulator SWOs; November 1, 2007

- FP-T-SAT-80; Simulator Configuration Management; September 28, 2007
- FP-T-SAT-81; Simulator Testing and Documentation; September 28, 2007
- SIMGL C3.3; Simulator Certification Testing; September 21, 2005
- SIMGL C1.4; Simulator Modifications and Core Load Changes (Completed for Unit 1); November 2, 2007
- ANSI/ANS-3.5-1985; Nuclear Power Plant Simulators for Use in Operator Training; October 25, 1985
- Regulatory Guide 1.149; Nuclear Power Plant Simulation Facilities for Use in Operator License Examinations; Revision 1; April 1987
- ANSI/ANS-3.4-1996; Medical Certification and Monitoring of Personnel Requiring Operator Licenses for Nuclear Power Plants; February 7, 1996
- Regulatory Guide 1.134; Medical Evaluation of Licensed Personnel for Nuclear Power Plants; Revision 3; March 1998
- Seven Licensed Operators' Medical Records; dated various
- TRR 01116172; Review Two Exam Bank Questions for Difficulty Level Changes; November 8, 2007
- TRR 01116174; Review Two JPMs for Difficulty Level; November 8, 2007

Procedures:
- FP-T-SAT-73; Licensed Operator Requalification Program Examinations; Revision 2
- JPM P000.042bAOT; Lineup for Transfer to Containment Sump Post-Accident Recirculation; Revision 4
- SEG # PB-LOR-07E-001S; High Impact Session – PZR Pressure Transmitter RTS, EH Malfunction and Containment Sump Recirculation; Revision 0
- EOP-1.3 Unit 1; Transfer to Containment Sump Recirculation – Low Head Injection; Revision 39
- FL-LOR-TPD; NMC Fleet Licensed Operator Requalification Training Program Description; Revision 0
- TRPR 33.0; Training Program Description; Licensed Operator Requalification Training Program; Revision 25
- OM 3.10; Operations Personnel Assignments and Scheduling; Revision 23; August 9, 2007
- FP-T-SAT-71; NRC Examination Security Requirements; Revision 0
- CAP 01040650; Simulator PPCS Failed Completely, Affecting LOR As Found; July 20, 2006
- CAP 01073895; EP Issues from LOR 2006 Annual Operating Exams; January 25, 2007
- CAP 01092718; LOR Cycle 07C Schedule Affected by Simulator Malfunctions; May 15, 2007
- CAP 01111841; RWST Temp Found High OOS on Logs; September 18, 2007
- CAP 01113938; Operations Quarterly Status Report Accuracy Questioned; October 9, 2007
- CAP 01115710; Annual Operating Exam Security Lapse Results in Rework; November 1, 2007
- NP 1.10.1; Record Keeping for NRC Licensed Operators; July 20, 2005
- OM 4.3.2; EOP/AOP Verification/Validation Process; Revision 15; October 29, 2007

CAPs/PCRs/TRRs Initiated for NRC-Identified Issues:
- CAP 01115978; Watchstander Restriction Form Not Filled Out Correctly; November 7, 2007
- CAP 01116144; PCRs Generated from CDBI Closed Out With No Action Taken; November 8, 2007
- CAP 01116160; Simulator PPCS Problems During Exams; November 8, 2007
- PCR 01116095; Revise EOP 1.3 Unit 1; November 8, 2007
- PCR 01116097; Revise EOP 1.3 Unit 2; November 8, 2007

1R13 Maintenance Risk Assessments and Emergent Work Control

- NP 10.3.6; Shutdown Safety Review and Safety Assessment; Revision 19
- Safety Monitor Calculation Reports for Units 1 and 2 for Applicable Work Weeks
- Work Week Execution Schedules for the Applicable Work Weeks
- Operator Logs for the Applicable Work Weeks

1R15 Operability Evaluations

Issue Reports:
- CAP 01111251; Discrepancy in CAF BHP Measured vs. Vendor Data; September 13, 2007
- OPR 154; Overload Concerns of Safeguards 480V AC Load Control and Motor Control Centers; Revisions 1 Through 3
- OPR 157; EDG Operability Related to Electrical Loading During Certain Accident Scenarios; Revision 3
- AR 01106938-01; Past Operability of P-32C; 10/25/2007
- CAP 01098680; P-32C SW Pump Vibration Nearing Acceptance Criteria Limit; June 24, 2007
- OPR 01098680; P-32C, Service Water Pump; Revision 0
- ACE 01098680-02; P-32C Vibration Issues; October 5, 2007
- CAP 01105929; P-32C SW Pump Fails IT-07C Testing; August 8, 2007
- CAP 01114171; OI 35C Requires Extensive Rewriting; October 11, 2007
- CAP 01119241; Concerns of PBNP's Use of IST Trend Data in OPRs; January 4, 2008
- CAP 01112660, 2P-29 Outboard Bearing Water Following IT-09A; September 24, 2007
- CAP 01113318, IT-09A Oil Analysis Results Not As Expected for 2P-29; September 27, 2007
- OPR1098358, Moisture Observed in Oil Sample From 2P-29 Outboard Bearing, Revision 2, November 3, 2007
- OPR1098358, Moisture Observed in Oil Sample From 2P-29 Outboard Bearing, Revision 3, November 4, 2007
- OPR1098358, Moisture Observed in Oil Sample From 2P-29 Outboard Bearing, Revision 4, November 7, 2007
- OPR1098358, Moisture Observed in Oil Sample From 2P-29 Outboard Bearing, Revision 5, November 10, 2007

Procedures:
- OI-35C; 480V Electrical Load Conservation; Revisions 3 and 4
- IT-07C; P-32C Service Water Pump (Quarterly); Revision 18

1R17 Permanent Plant Modifications

- Engineering Modification 05-006 and Engineering Changes EC1590 and 1591 Associated With the Replacement of the EDG Heat Exchangers for EDGs G01 and G02

1R19 Post-Maintenance Testing

Procedures:
- RMP 9216-5;Service Water Pump Bowl Assembly Inspection and Maintenance; Revision 3
- IT 07E; P-32E Service Water Pump (Quarterly); Revision 19
- RMP 9387; AC Induction Motor MCE Testing Procedure; Revision 4
- IT-21; Charging Pumps and Valves Quarterly; Revision 18
- RMP 9003-1; Charging Pump Overhaul; Revision 6

Work Orders:
- WO 302859-01; Service Water Pump Maintenance; October 24, 2007
- WO 300182-02; P-32E Service Water Pump Lower Than Expected Insul Resistance Reading; October 24, 2007
- WO 219880; CVCS Charging Pump Modification – Pump 1P2B Renovation; Revision 0

1R22 Surveillance Testing

Procedures:
- IT-65; Containment Isolation Valves Quarterly; Revision 35
- PBTP 158; Leak rate Testing of 2SC-966C Containment Isolation Valve at Power; Revision 0
- IT-09A; Cold Start of the Turbine Driven Auxiliary Feedwater Pump Unit 2; Revision 45
- TS-81; Emergency Diesel Generator G01; Revision 75
- TS-82; Emergency Diesel Generator G02; Revision 76

1R23 Temporary Plant Modifications

Engineering Change:
- EC11633; Furmanite Injection of 2MS-232A MSR Valve

Work Orders:
- WO 340064; Furmanite Injection of 2MS-232A MSR Valve
- WO 346804; Furmanite Injection of 2MS-232A MSR Valve

2OS3 Radiation Monitoring Instrumentation and Protective Equipment

Issue Reports:
- Point Beach Nuclear Plant Radiation Monitoring System Health Report; December 6, 2007
- Snapshot Self-Assessment Report; SCBA Maintenance and User Training; November 30, 2007
- Snapshot Self-Assessment Report; IP 71121.03 Inspection; November 30, 2007
- Snapshot Self-Assessment Report; 2006 INPO Area for Improvement - Radiation Monitoring Instrument Program; November 23, 2007
- Radiation Protection Instrument Inventory and Calibration Due Date Report; December 7, 2007
- Radcal Corporation Certificate of Conformance for Electrometer/Ion Chamber Model 20-X5-1800 (SN 21707), Model 20X5-3 (SN 21548) and Model 20-X5-60 (SN 21344); September 21, 2005
- Report of Calibration for the Canberra Fastscan Whole Body Count System at the Point Beach Nuclear Plant; January 26, 2007
- Report of Evaluation of Isotopic Mixture and RP Programs; January 31, 2007
- Calibration Record for MGP Instrument Model AMP-100 (SN 474103); March 24, 2007
- Calibration Record for Eberline Instrument Model AMS-4 (SN A021); January 27, 2007
- Point Beach Emergency Plan Manual; EP 7.0 - Emergency Facilities and Equipment; Revision 51
- Qualification Matrix and Training Status for Respiratory Protection; December 11, 2007
- Lesson Plan No. PB-SHE-004-SCRL; Respiratory Protection; Revision 1
- Scott Posicheck 3; Visual and Functional Test Records for Point Beach SCBA Units; March 20, 2007

Procedures:
- HPIP 7.52.4; PM-7 Personnel Monitor Checks; Revision 12
- HPIP 7.52.1; Personnel Contamination Monitor (PCM-1B/1C) Source Response Check; Revision 13
- HPIP 5.66; Functional Check of the Gamma-60 Portal Monitor; Revision 21
- HPIP 2.1.1; Response Checks of Portable Survey Instruments; Revision 9
- HPIP 1.74; Operation of the Canberra Whole Body Counter; Revision 7
- HPCAL 3.2; Area Monitor Calibration Procedure DA1-1 and DA1-6 Detector Assemblies and Associated Calibration Records for Unit 1 and Unit 2 Charging Pump Room (Low Range) ARMs; December 19, 2006, and September 15, 2006
- HPCAL 3.3; Area Monitor Calibration Procedure DA1-4 and DA1-5 Detector Assemblies and Associated Calibration Records for Unit 1 and Unit 2 Charging Pump Room (High Range) ARMs; February 15, 2007, and February 12, 2007
- HPCAL 3.2 Calibration Record for Unit 1 and Unit 2 Seal Table ARMs; April 1, 2007, and October 15, 2006
- HPCAL 3.2 Calibration Record for Unit 1 and Unit 2 Post Accident Sample Line Monitors; August 13, 2007, and April 17, 2007
- HP CAL 3.2 Calibration Record for Safety Injection Pump Room Low Range and High Range ARMs; September 18, 2006, and July 17, 2006
- 2ICP 13.017; Containment High Range Radiation Monitoring System Channels 2RE−126, 2RE−127, 2RE−128 Calibration; December 12, 2006
- 1ICP 13.017; Containment High Range Radiation Monitoring System Channels 1RE−126, 1RE−127, 1RE-128 Calibration; March 14, 2007
- HPCAL 3.11; Containment High Range Detector Response Check Surveillance Record, Unit 1 Detectors (1RE−126, 127 and 128), April 11, 2007; and Unit 2 Detectors (2RE−126, 127 and 128), October 16, 2006
- HPCAL 1.10.2; Verification of J.L. Shepherd Model 89 Calibrator Dose Rates (Revision 1) and Associated Output Verification for Calibrator No. 8269 and No. 8228; September 28, 2006
- HPCAL 1.1; Portable Survey Instrument Calibration, Repair and Response Checks; Revision 18
- NMC Fleet Procedure FP-RP-ICC-01; Instrument Control and Calibration/Functional Testing Frequencies of RP Instruments; Revision 3
- HPCAL 1.38; Calibration of the Portable Neutron Survey Instrument Analog Smart Portable (ASP-1), and Associated Calibration Record (Instrument No. 9459); March 9, 2007
- HPCAL 2.8; Eberline PCM-1B Personnel Contamination Monitor Calibration Procedure and Associated Calibration Record for Monitor No. 7737, October 17, 2007; No.7738, March 30, 2007; and No. 7739, May 8, 2007
- HPCAL 2.8.1; Personnel Contamination Monitor Detector Efficiency Determination and Associated Record for Monitor No. 7739; July 13, 2007
- HPCAL 2.11.1; Calibration of the Gamma-60 Portal Monitor and Associated Calibration Record for Monitor No. 9485, March 12, 2007; and No. 9486, February 22, 2007
- HPCAL 2.21; Calibration of the Eberline Personnel Monitor PM-7 and Associated Calibration Record for Monitor No. A112 (November 28, 2007); No. A113 (October 29, 2007); and No. A114; (September 21, 2007)
- HPCAL 2.15; Small Articles Monitor Type SAM 9/11 Calibration and Efficiency and Associated Calibration Record for Monitor No. 2; September 26, 2007
- PC 75 Part 1; Monthly and Turnaround Maintenance for the Scott Model 4.5 Self-Contained Breathing Apparatus and Associated Surveillance Records for January 2006 through December 2007
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- PBF-4077(c); Self-Contained Breathing Apparatus Inspection and Maintenance Records for 2006 and 2007
- HPIP 4.51.4; Scott Self-Contained Breathing Apparatus; Revision 8

Work Orders:
- CAP 01048997; Compliance with Fleet Procedure; September 8, 2006
- CAP 01080787; Gamma-60 Source Check Concerns; March 6, 2007
- CAP 00906738; RP Survey Instrument Response Checks and Instrument Sign-Out; February 7, 2006
- CAP 01081898; Failure of Meter Movement for C-59 Area Monitor RE-111; March 13, 2007
- CAP 01091161; Lack of Bases for RP Equipment Functional Check; May 5, 2007
- CAP 01087730; Possible Trend With Poor Teletector Performance; April 14, 2007

4OA1 Performance Indicator Verification

Issue Reports:
- Monthly Data Elements for RETS/ODCM Radiological Effluents; December 2006 – November 2007
- Liquid and Gaseous Effluent Summary Data and Dose Calculation Results; March 2007

4OA2 Problem Identification and Resolution

Procedures:
- NP 2.1.4 Operator Burdens; Revision 7

4OA3 Followup of Events and Notices of Enforcement Discretion

Issue Reports:
- CAP 01111841; RWST Temp Found High OOS on Logs; September 18, 2007
- RCE 01111841-01; Unit 2 Refueling Water Storage Tank Temperature High Resulting in Unplanned TSAC; Revision 1
- RCE 01090456-01; 1P-29 Turbine Driven Auxiliary Feedwater Pump Outboard Bearing Issues

4OA5 Other Activities

Documents:
- EPRI Terry Turbine Guide; Terry Turbine Maintenance Guide, AFW Application TR-1007461
- VTM 0004 Manual: Terry Steam Turbine Company; Auxiliary Feedwater Pump Turbine Drive; Revision 30
- Technical Data Sheet; Loctite High Temp Red
- Technical Data Sheet; Turbo 50
- Technical Data Sheet; Temp Tite II String Kit
- RCE 01090456-01; IP-29 Turbine Driven Auxiliary Feedwater Pump Outboard Turbine Bearing Issues
- MPR Report; Point Beach Nuclear Station; Water Containment of AFW Turbine Lube Oil
- Memo on OST Device Drain Plug – Justification of Drain Plug Removal
- Station Logs – From Present Back to June 21, 2007; Focus on Auxiliary Feed Runs
- OCC Logs – November 2006 Outage, September 2007 Overhaul, and November 2007 Overhaul
- 2P-29 Event Folders
- Applicable Oil Analysis Results Record

- RCE 96-08; Unit 1 Reactor Taken Critical with Both 1P-29 Turbine-Driven Auxiliary Feedwater Pump Discharge Motor-Operated Valves (1AF-4000, 1AF-4001) Found Shut
- RCE 98-150; Unit 1 Turbine-Driven Auxiliary Feed Pump Turbine Maintenance Rework
- RCE 01115748; 2P-29 AFW Pump Moisture in Oil

Procedures:
- RMP 9044-1; Auxiliary Feedwater Pump Terry Turbine Overhaul
- IT-09A; Cold Start of Turbine-Driven Auxiliary Feed Pump and Valve Test
- OI-62B; Turbine-Driven Auxiliary Feedwater System

Condition Reports and Work Orders:
- CAP 01049806; 1P-29 AFW Pump S/D Due to Low Oil Level in Bubbler; September 12, 2006
- CAP 01051133; Oil Level Problems Encountered During PMT for 1P-29 AFP; September 19, 2006
- CAP 01062958; Reinstallation of Insulation for 2P-29 TDAFW Pump not Done; November 20, 2006
- CAP 01068606; 1P-29 Aux Feed Pump Suction Sodium Lab Analysis was High; December 20, 2006
- CAP 01086108; Additional Paint Removal Required – Not correctly Identified; April 5, 2007
- CAP 01097185; Differences Noted Between RMP 9044-1 and EPRI Guide; June 17, 2007
- CAP 01097732; Improvement Recommendations for RMP 9044-1; June 20, 2007
- CAP 01097736; Declining Trend in 2P-29 TDAFW Pump Speed Noted; June 20, 2007
- CAP 01098358; Moisture Observed in Oil Sample from 2P-29 Turbine Reservoir; June 21, 2007
- CAP 01098364; AFW Steam Pipe Supports Lubra-Plates Have Been Painted; June 22, 2007
- CAP 01098445; Benchmark in Service Testing of Aux Feed Systems; June 22, 2007
- CAP 01098525; Unit 1 and 2 TDAFW Pump Oil Sampling; June 22, 2007
- CAP 01098536; No Specific Training for Turbine Driven AFPs; June 22, 2007
- CAP 01098615; U2R28 P-29-T: GL 89-13 HX PM Not Properly Documented; June 22, 2007
- CAP 01098626; AFW Casing Sealant Review; June 23, 2007
- CAP 01098633; 1P-29 TDAFW Pump Sentinel Valve Opened on Start; June 23, 2007
- CAP 01099142; Unable to Analyze Water Content of Oil Sample; June 26, 2007
- CAP 01099272; Oil Sample for 2P-29-T May Not Have Been Taken Correctly; June 26, 2007
- CAP 01099402; 2007 AFW Inspection – Review of Additional Engineer Programs; June 27, 2007
- CAP 01099576; 2P-29 TDAFWP Oil Sample High Water Content; June 28, 2007
- CAP 01099876; Water Content Analysis Results for 2P-29-T OB Bearing; June 29, 2007
- CAP 01100698; IT-08A/IT-09A Do Not Contain 1996 Reg Commitments; July 7, 2007
- CAP 01100865; 1P-29-T Coupling Stretch Not Verified After Re-alignment; July 9, 2007
- CAP 01100874; RMP 9044-1 Contains Vague Guidance for Thomas Coupling Setting; July 9, 2007
- CAP 01101114; Potential Preconditioning of 1(2)P-29 TDAFW Pump; July 11, 2007
- CAP 01101562; 2P-29 Oil Sample Put on HOLD by Supply Chain Buyer; July 12, 2007
- CAP 01102282; 1P-29 Terry AFP Thomas Coupling Setting Concerns; July 18, 2007
- CAP 01102417; RMP 9044-1, Revision 12, Provides Incorrect Acceptance Criteria; July 19, 2007
- CAP 01102492; Quarantine Oil Samples Taken from 2P-29-T Under WO 335172; July 19, 2007
- CAP 01102642; 2P-029-T Oil Dripping from Outboard Bearing Housing Seal; July 19, 2007
- CAP 01102655; Water Still Indicated in Oil from 2P-29-T OB BRG; July 20, 2007

- CAP 01102868; Higher Than Expected Water in 2P-29-T OB BRG Post Run Sample; July 21, 2007
- CAP 01102875; 2P-29 Appendix R Functionality; July 21, 2007
- CAP 01102902; Documentation of Observation, 2P-29-T Temperature Indication; July 22, 2007
- CAP 01102903; Verified Steam Leak at Seal on 2P-29-T OB Bearing; July 22, 2007
- CAP 01103469; Form for Bearing Stabilization on 1P-29 and 2P-29 Is Not Formalized; July 25, 2007
- CAP 01103520; Potential Improper Oil Issued for 2P-29 Aux Feed Pump; July 25, 2007
- CAP 01103623; Question Concerning Bearing Coolers on P-029 Turbines; July 26, 2007
- CAP 01103841; 1P-29T and 2P-29T OB Steam Gland Drain Lined Pitch Is Incorrect; July 27, 2007
- CAP 01106373; Evaluate Use of New Governor Drive Coupling on P-29T; August 10, 2007
- CAP 01107473; Oil Storage Requirements Questioned; August 17, 2007
- CAP 01108275; AFP Bearings Failed Vendor Dimensional Inspection; August 23, 2007
- CAP 01108351; 2P-29-T Outboard Bearing Aluminum Fill Plug; August 23, 2007
- CAP 01108355; 1P-29-T Oil Analysis Results Indicated As Alarm; August 23, 2007
- CAP 01108426; 2P-29-T Governor Oil Level High; August 23, 2007
- CAP 01108429; Unexpected Oil Leak Rate While Running 2P-29-T; August 23, 2007
- CAP 01108576; FPL AFW System Focused Assessment – Operations Observations; August 24, 2007
- CAP 01109045; Oil Analysis Results Questioned; August 28, 2007
- CAP 01109571; P-29-T Inbound Bearing Oiler Upper Casting Slightly Damaged; August 31, 2007
- CAP 01109572; 2P-29-T Oiler Height Settings; August 31, 2007
- CAP 01112474; 2P-29 Pump Outboard Packing Has Excessive Leakage; September 21, 2007
- CAP 01112475; 2P-29 Outboard Turbine Bearing High Temp Alarm During IT-9A; September 21, 2007
- CAP 01112533; 2P-29-T Changing Oil and Stabilization; September 21, 2007
- CAP 01112567; Terry Turbine Gland Case leak Off Lines Not Optimal; September 22, 2007
- CAP 01112579; Wrong Revision of Procedure Used for 2P-29-T Work; September 22, 2007
- CAP 01112587; 2P-29-T TDAF Wheel Lap Measurement; September 22, 2007
- CAP 01112596; September 21, 2007 2P-29 Oil Analysis Results; September 22, 2007
- CAP 01112597; 2P-29-T Outboard Terry Turbine Bearing; September 22, 2007
- CAP 01112609; 2P-29-T Outboard BRG Thermocouple Damaged During BRG Crush; September 23, 2007
- CAP 01112626; 2P-29-T Outboard Bearing Oil Ring Contacting Oil Cooler; September 23, 2007
- CAP 01112631; 2P-29-T Terry Turbine Casing Bolts; September 23, 2007
- CAP 01112641; RMP 9044-1 Did Not Have Correct torque Value; September 23, 2007
- CAP 01112660; 2P-29-T OB BRG Water Following IT-09A; September 24, 2007
- CAP 01113029; RMP 9044-1 Wrong Revision Used for 2P-29-T Work; September 25, 2007
- CAP 01113318; IT-09A Oil Analysis Results Not As Expected for 2P-29-T; September 27, 2007
- CAP 01113438; P-29-T Oil Cooler Differences Outboard End; October 1, 2007
- CAP 01113972; IT-290B and IT-295B Makes Reference to Replaced ERPI Guide; October 10, 2007
- CAP 01113973; Differences Between EPRI Guide and IT-08A, B and IT-09A,B; October 10, 2007
- CAP 01113978; EPRI Terry Turbine Manual Recommendation for AF; October 10, 2007
- CAP 01115697; 2P-29 TDAFP Inbound Pump Bearing Oil Leak; November 1, 2007

- CAP 01115748; 2P-29 Moisture in Oil Concern; November 1, 2007
- CAP 01115768; Visual Indications Post IR-09A on November 2, 2007 for Oil; November 2, 2007
- CAP 01115778; Oil Sampling Concerns for 2P-29 AFW Pump; November 2, 2007
- CAP 01115808; Oil Analysis Results for 2P-29-T on November 3, 2007; November 3, 2007
- CAP 01115810; 2P-29 Returned to OPS in an Operable But Degraded Condition; November 3, 2007
- CAP 01115819; November 2, 2007 Log Entry for 2P-29 Availability Incomplete; November 4, 2007
- CAP 01115832; Appears Samples Not Taken Per Request; November 5, 2007
- CAP 01115952; Oil Analysis Results for 2P-29-T from November 5, 2007; November 6, 2007
- CAP 01116158; 2P-29 Governor Gear Drive Oil Color; November 8, 2007
- WO 219237; Uncouple 2P-29 Per Callup Text; March 8, 2006
- WO 219238; Inspect Inboard and Outboard Bearing; March 8, 2006
- WO 219239; Emergency Governor Inspection; March 8, 2006
- WO 219240; Sample Oil in 2P-29 Turbine Governor; March 8, 2006
- WO 219448; Perform Overhaul; October 24, 2006
- WO 267802; ten-Year Overhaul; November 12, 2006
- WO 268232; Sample Oil in 2P-29 Turbine Governor; November 12, 2006
- WO 268233; GL 89-13 – Inspect Bearing Oil Coolers; November 12, 2006
- WO 268234; Emergency Governor Inspection; November 12, 2006
- WO 268235; Uncouple 2P-29 Pump from Its Turbine; November 12, 2006
- WO 334308 Auxiliary Feedwater Pump Terry Turbine Overhaul; September 12, 2007
- WO 334597; Sample and Change Oil as Required; November 9, 2007
- WO 335167; Sample and Change Oil As Required; June 28, 2007
- WO 346758; Auxiliary Feedwater Pump Terry Turbine Overhaul; November 2, 2007

NRC-Identified Condition Reports

- AR 01100068; Closeout Based on Incorrect Info
- AR 01100293; Benchmarking/Snapshot Evaluation for VTI
- AR 01100509; Potential HU Crosscut
- AR 01100985; Cable ZA1327FA Not Included in App
- AR 01101029; Error Noted on Drawing WEST 499B466
- AR 01101383; Near Miss During ILT NRC Exam
- AR 01101421; Untimely Corrective Actions
- AR 01101444; Compliance With Appendix R, Section III
- AR 01101461; Potential Coincident Fire Induced Failure
- AR 01101506; NFPA 13 Issues With G-01 and G-02 R
- AR 01101596; Procedure EOP-3 Change Needed for Bistable Tube Rupture
- AR 01101667; Inconsistent/Inadequate Direction
- AR 01101704; Procedure EOP-3 Steps Out of Sequence
- AR 01102113; Scaffold Clearance Questioned
- AR 01102590; Incorrect Description of Pushbutton
- AR 01103769; Error in Calculation S-11165-035-SW
- AR 01105181; Fire Extinguishers Removed for Annu
- AR 01105290; Inappropriate Screened AR 11033415
- AR 01105804; PI Indicator Does Not Match INPO CD
- AR 01105948; PI-2849 Discharge Pressure on E SW
- AR 01105993; Quench Curve Check Performed
- AR 01106042; Fluctuations Seen on P-32E SW Pump

- AR 01106118; Façade Groundwater Samples Not Shipped
- AR 01107098; Missing Bolts on Subsoil Drainage
- AR 01107355; Stalling of MOVs while Load Sequencing
- AR 01107452; Lube oil Tank Rupture
- AR 01107461; NRC RP Inspection: Groundwater
- AR 01107485; Weakness Identified in 10 CFR 50.75(g)
- AR 01107520; Debris in Subsoil Drainage System
- AR 01107630; Create Engineering Documents for Flooding
- AR 01107634; Formally Verify Function and Capacity
- AR 01108334; Radiodine Results High – Evaluate
- AR 01108724; Supplement Needed for LAR 249
- AR 01109665; LAR 247 submittal Being Withdrawn
- AR 01109968; 2007 Mid-Cycle Performance Review
- AR 01109992; 2007 EP Drill
- AR 01111043; LER 2007-003 Related AR Severity
- AR 01111296; RCE-01075472 Not Revised per PARB
- AR 01112896; Improvements in Posting and Access
- AR 01112924; Postings in RCA Yard Found Faded
- AR 01112934; Cleanliness in the Drumming Room
- AR 01112981; Point Beach Nuclear Plant Flood Watch Commitment Information
- AR 01113207; NRC Radwaste Inspection/ATCOR Equip
- AR 01113226; NRC Question on 10 CFR 20, Appendix G, A.3
- AR 01113277; Material Condition
- AR 01113347; NRC Radwaste Inspection Request
- AR 01113420; NRC Inspection Debrief
- AR 01113508; Security Documentation Enhancement
- AR 01113563; Security Weapons Documentation
- AR 01114426; Procedure Noncompliance of NP 8.4.1
- AR 01114599; PC 99 May Need To Be Implemented
- AR 01114637; Material in Yard
- AR 01114731; Loose Materials Found in the Protected Area
- AR 01115102; Weakness Identified in Crew Information
- AR 01115108; Unit 2 MFRV Turnover Less Than Complete
- AR 01115189; Scaffold Material in Contact
- AR 01115311; Small Coolant Leak on G-04 EDG
- AR 01115486; Point Beach Nuclear Plant Use of Maintenance Run
- AR 01115556; Requirements of NP 7.7.5 for Maintenance
- AR 01115620; Error Found by Review of Maintenance
- AR 01115703; OPR 01114308 Requires Revision
- AR 01115713; Number of Maintenance Rule Functional Failures
- AR 01115729; Documentation of D-06 Performance
- AR 01115818; Potential SSD Equipment Missing From Documentation
- AR 01115819; November 2, 2007 Log Entry for 2P-29
- AR 01115820; LAR 256, ILRT Interval Extension
- AR 01115838; Revision 3 Required for OPR 1098358
- AR 01115876; EPRI Guidance Not Included in RMP 9
- AR 01115881; Wording in OPR 1098358 May Be Misleading
- AR 01115951; Unit 2 TDAFWP Event – NRC Question
- AR 01115978; Watchstander Restriction Form Not Filed
- AR 01116011; 2P-29 Oil Samples
- AR 01116150; Discrepancy in TAN Values

- AR 01116158; 2P-29 Governor Gear Drive Oil Color
- AR 01116250; Lack of Sample Splitting Procedure
- AR 01116334; Minor Shaft Pitting – 2P-29
- AR 01116442; 2P-029-T Oil Dregs
- AR 01116533; LAR 256 ILRT Extension Request
- AR 01116589; MSPI Records Missing From EDMS
- AR 01116594; HPIT – Confirmation Bias in Engineering
- AR 01116619; 2P-29-T - OPR Testing Methodology
- AR 01116647; Procedural Temporary Change Chart
- AR 01116658; General Observations Regarding 2P-0
- AR 01116673; Clarification Needed for Sealant
- AR 01116688; Review/Revise OPR 1098358
- AR 01116794; Minor Error Found in CDE
- AR 01116819; Unavailability Guidance for MR and NEI
- AR 01117062; 1RMP-9096 and SLP 2 Revisions Required
- AR 01117126; Revise/Correct EOP Setpoint for L.25 and L.4
- AR 01117152; Revise IP-29 Root Cause to Address Issue
- AR 01117163; MI 32.9 Scaffold Stabilization Criteria
- AR 01117170; Rubber Pads Not Installed on RCP
- AR 01117200; NRC Noted Service Water Drawing – Verification Temperature Indicator
- AR 01117205; NRC Noted Auxiliary Feedwater Drawing
- AR 01117350; IT 40/45 Do Not Contain “Caution” Statements
- AR 01117459; Façade Wells – H-3 in Ground Water
- AR 01117637; Errors in Calculations - PCI-5344-S02
- AR 01117860; Provide Preliminary Technical Basis – Temporary Storage Items
- AR 01118002; Errors in Calculations – PCI-5344-S01
- AR 01118105; ACE 10434692 – Actions Not Identified
- AR 01118106; PM-7 Functional Check Periodicity
- AR 01118107; H3 Sample Results
- AR 01118141; License Amendment Quality/Timeliness
- AR 01118144; Errors in Structural Calculation
- AR 01118148; Rigging Evaluation Documentation
- AR 01118185; Evaluate Load Handling Procedure
- AR 01118189; NRC BL 2007-01, Security Officer
- AR 01118194; Recommended Improvement to DG-M10
- AR 01118195; SCBA LP Does Not Show How to Change
- AR 01118200; Support Model in Calculation PBNP-9
- AR 01118202; Low Design Margin for Plant Component
- AR 01118207; SCBA Monthly Location Inspection
- AR 01118213; Consider Completing and Audit on SC
- AR 01118259; NRC Inspection Observation
- AR 01118722; NRC Concern About Secondary Sample
- AR 01118844; Clarification Regarding Operability – Implement Recommendations
- AR 01118847; NRC Submittal Rejected

LIST OF ACRONYMS USED

AC	Alternating Current
ACE	Apparent Cause Evaluation
AFW	Auxiliary Feedwater
AOP	Abnormal Operating Procedure
ARM	Area Radiation Monitor
ASME	American Society of Mechanical Engineers
CAP	Corrective Action Program Document (Condition Report)
CEDE	Committed Effective Dose Equivalent
CFR	Code of Federal Regulations
CoC	Certificate of Compliance
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
EPRI	Electric Power Research Institute
FSAR	Final Safety Analysis Report
IEEE	Institute of Electrical & Electronic Engineers
IMC	Inspection Manual Chapter
IP	Inspection Procedure
ips	Inches Per Second
IR	Inspection Report
ISI	Inservice Inspection
IST	Inservice Test
IV	Independent Verification
JPM	Job Performance Measure
kV	Kilovolt
kW	Kilowatt
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LHRA	Locked High Radiation Area
LOCA	Loss of Coolant Accident
LOOP	Loss of Off-site Power
LORT	Licensed Operator Requalification Training
MG	Motor-Generator
MOV	Motor-Operated Valve
mrem	Millirem
MSPI	Mitigating Systems Performance Index
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NIOSH	National Institute of Safety & Health
NMC	Nuclear Management Corporation
NRC	U.S. Nuclear Regulatory Commission
ODCM	Offsite Dose Calculation Manual
OM	Operational Maintenance
OPR	Operability Evaluation
OWA	Operator Workaround
PI	Performance Indicator
PI&R	Problem Identification and Resolution
PM	Planned or Preventative Maintenance

PMT	Post-Maintenance Testing
ppm	Parts Per Million
PRA	Probabilistic Risk Assessment
QA	Quality Assurance
RCA	Radiologically Controlled Area
RCE	Root Cause Evaluation
RETS	Radiological Effluent Technical Specification
RHR	Residual Heat Removal
RP	Radiation Protection
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
RWST	Refueling Water Storage Tank
SAT	Systems Approach to Training
SCBA	Self-Contained Breathing Apparatus
SDP	Significance Determination Process
SSC	Structure, System, or Component
SW	Service Water
TDAFW	Turbine-Driven Auxiliary Feedwater
TS	Technical Specification
URI	Unresolved Item
WO	Work Order
VIO	Violation