UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
2443 WARRENVILLE ROAD, SUITE 210
LISLE, IL 60532-4352

February 6, 2009

EA-08-274

Mr. Larry Meyer
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 05000266/2008005 AND 05000301/2008005

Dear Mr. Meyer:

On December 31, 2008, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Point Beach Nuclear Plant, Units 1 and 2. The enclosed report documents the inspection results, which were discussed on January 7, 2009, 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, four NRC-identified and three self-revealed findings of very low safety significance were identified. All of these findings were determined to involve violations of NRC requirements. However, because of their very low safety significance and because the issues were entered into your corrective action program, the NRC is treating the issues as Non-Cited Violations (NCVs) in accordance with Section VI.A.1 of the NRC Enforcement Policy.

If you contest the subject or severity of any NCV, 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 and its enclosure 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 05000266/2008005; 05000301/2008005
w/Attachment: Supplemental Information

cc w/encl: M. Nazar, Senior Vice President and
Chief Nuclear Officer
J. Stall, Executive Vice President, Nuclear and
Chief Nuclear Officer
A. Khanpour, Vice President, Engineering Support
Licensing Manager, Point Beach Nuclear Plant
R. Hughes, Director, Licensing and Performance Improvement
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A. Fernandez, Senior Attorney
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P. Wells, (Acting) Vice President, Nuclear
Training and Performance Improvement
J. McCarthy, Vice President, Point Beach Recovery
J. Bjorseth, Plant General Manager
K. Duveneck, Town Chairman, Town of Two Creeks
Chairperson, Public Service Commission of Wisconsin
J. Kitsembel, Electric Division, Public Service Commission of Wisconsin
P. Schmidt, State Liaison Officer

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Letter to L. Meyer from M. Kunowski dated February 6, 2009

SUBJECT: POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2, NRC INTEGRATED INSPECTION REPORT 05000266/2008005 AND 05000301/2008005

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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:	05000266/2008005; 05000301/2008005
Licensee:	FPL Energy Point Beach, LLC
Facility:	Point Beach Nuclear Plant, Units 1 and 2
Location:	Two Rivers, WI
Dates:	October 1, 2008, through December 31, 2008
Inspectors:	R. Krsek, Senior Resident Inspector R. Ruiz, Resident Inspector C. Acosta, Reactor Inspector K. Barclay, Reactor Engineer D. Betancourt, Reactor Engineer D. Dodson, NSPDP – Headquarters P. Higgins, Resident Inspector – Kewaunee J. Jacobson, Reactor Inspector J. Jandovitz, Project Engineer R. Jickling, Senior Emergency Preparedness Inspector D. McNeil, Senior Operations Engineer V. Meghani, Reactor Inspector M. Phalen, Health Physicist W. Slawinski, Senior Health Physicist R. Winter, Reactor Inspector
Observer:	E. Sanchez-Santiago, NSPDP – Region III
Approved by:	Michael Kunowski, Chief Branch 5 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

IR 05000266/2008005, 05000301/2008005; 10/01/2008-12/31/2008; Point Beach Nuclear Plant, Units 1 & 2; Inservice Inspection (ISI) Activities; Outage Activities; Radioactive Gaseous and Liquid Effluent Treatment and Monitoring Systems; Follow-up of Events and Notices of Enforcement Discretion; and Other Activities.

This report covers a three-month period of inspection by resident inspectors and regional specialists. Seven Green findings were either self-revealed or identified by the inspectors this quarter. All of the findings that 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-Revealed Findings

Cornerstone: Initiating Events

- Green. A finding of very low safety significance and associated NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was self-revealed for the failure to have inspection procedures appropriate to the circumstances for the Unit 1 and Unit 2 containment polar cranes and their integral support structures. Specifically, station routine maintenance procedure 1(2) RMP 9118-1(2), "Containment Building Crane OSHA Operability Inspections," did not require that the polar crane lateral restraint bolts be inspected to ensure that they do not show signs of degradation or movement, e.g., flaking paint or being backed out of position. As a result, improperly installed bolts went undiscovered by the licensee until a failed bolt was found on October 16, 2008, lying on the containment floor. The discovery prompted further inspection of the entire crane support structure and led to the de-rating of the polar crane's lifting capacity from 100 tons to 40 tons. In addition to conducting an extent-of-condition inspection, the licensee entered the issue into its corrective action program (CAP), replaced all degraded bolts, and performed an apparent cause evaluation.

  The finding was determined to be more than minor because the finding was associated with the Initiating Events Cornerstone attribute of equipment performance and affected the cornerstone objective of limiting the likelihood of those events that challenge critical safety functions during shutdown. Specifically, failing to visually inspect critical bolting locations on crane supports could have allowed the use of the polar crane for heavy load lifts while in a degraded condition, increasing the likelihood of a load drop. The inspectors determined that the finding could be evaluated in accordance with IMC 0609, Appendix G, "Shutdown Operations SDP," dated February 28, 2005. The issue did not need a quantitative assessment and screened as Green using Figure 1. This finding has a cross-cutting aspect in the area of human performance, resources, for the failure to have complete and accurate procedures in place. Specifically, the vague and insufficient detail in the crane inspection procedures contributed to the licensee's failure to perform an adequate inspection to identify degraded components prior to their failure [H.2(c)]. (Section 1R20.3)

- Green. The inspectors identified a finding of very low safety significance and associated NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," for the failure to adequately perform boric acid leak evaluations for boric acid leaks as required by the Boric Acid Program. The licensee entered this issue into its CAP and was evaluating corrective actions at the end of the inspection period.

  This finding was determined to be more than minor because it was associated with the human performance attribute of the Initiating Events Cornerstone and affected the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown, as well as power operations. The inspectors used IMC 0609, "Significance Determination Process," Attachment 4, "Phase 1 - Initial Screening and Characterization of Findings," Table 4a for the Initiating Events Cornerstone, dated January 10, 2008, and determined the finding was of very low safety significance (Green) because the issue did not result in exceeding the Technical Specification (TS) limit for identified reactor coolant system (RCS) leakage or affect other mitigating systems resulting in a total loss of their safety function. The inspectors also determined that the finding has a cross-cutting aspect in the area of human performance, work practices component, because the licensee did not effectively communicate expectations regarding procedural compliance and personnel following procedures [H.4(b)]. (Section 1R08.1b)

Cornerstone: Mitigating Systems

- Green. A finding of very low safety significance and associated NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was self-revealed for the failure to have procedures appropriate to the circumstances for the draindown of the RCS from a solid plant condition. Specifically, procedure OP-4D, "Draining the Reactor Coolant System," did not require that the pressurizer level instrumentation reference line be filled within a defined period of time to ensure that the pressurizer level instrumentation functioned properly prior to draining the RCS. This resulted in the licensee draining approximately 2,000 gallons of RCS from the pressurizer without a valid control room indication of pressurizer level. The licensee performed an apparent cause evaluation and implemented corrective actions to address the procedure deficiencies and lessons learned from this finding.

  The finding was determined to be more than minor because the finding was associated with the Mitigating Systems Cornerstone attribute of operating procedure quality 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). Specifically, the pressurizer level instrumentation is utilized during shutdowns to detect and manually initiate mitigating actions for uncontrolled RCS inventory reductions. The inspectors determined that the finding could be evaluated in accordance with IMC 0609, Appendix G, "Shutdown Operations SDP," dated February 28, 2005. The inspectors used Checklist 2 contained in Attachment 1 and determined that the finding required a Phase 2 analysis since the finding increased the likelihood of loss of RCS inventory based on level deviation in the control room (Section II.A. of Checklist 2). The inspectors and senior reactor analyst determined through Phase 2 analysis that this issue is best characterized as a finding of very low safety significance (Green). The inspectors also determined that the finding has a cross-cutting aspect in the area of problem identification and resolution, corrective action program, because the licensee failed to take appropriate corrective actions to address safety issues and adverse trends associated with the pressurizer level instrumentation in a timely manner, commensurate with their safety significance and complexity [P.1(d)]. (Section 1R20.1)

- Green. The inspectors identified a finding of very low safety significance and associated NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," for the failure to appropriately implement work orders for the installation of the Z-296-B3 debris interceptor. As a result, this portion of the modification was not installed as designed when the modification was completed and the Unit 1 reactor transitioned to Mode 3. The licensee took remedial corrective actions to correct the installation deficiency and at the end of the inspection period, the licensee continued to perform an apparent cause evaluation.

  The finding was determined to be more than minor because the finding was associated with the Mitigating Systems Cornerstone attributes of initial modification design control and human performance, 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 inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Phase 1 - Initial Screening and Characterization of Findings," Table 4a for the Mitigating Systems Cornerstone, dated January 10, 2008. The inspectors determined that the finding was of very low safety significance (Green) because the finding did not involve a design or qualification deficiency, did not represent an actual loss of safety function, or represent a single train loss of safety function for greater than the Technical Specification-allowed outage time, and was not potentially risk-significant for external events. This finding has a cross-cutting aspect in the area of human performance, work practices, because personnel work practices for the installation did not utilize the available human error prevention techniques, specifically self and peer checking, and the use of a questioning attitude [H.4(a)]. (Section 1R20.2)

Cornerstone: Barrier Integrity

- Green. A finding of very low safety significance and associated NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," was self-revealed upon discovery of the use of a non-conservative setpoint for the Low Temperature Overpressure Protection (LTOP) systems for Units 1 and 2. Specifically, licensee calculation 2000-0001, "RCS [Reactor Coolant System] Pressure and Temperature Limits and Low Temperature Overpressure Protection Setpoints Applicable through 32.2 EFPY – Unit 1 and 34.0 EFPY – Unit 2," established an LTOP setpoint of 500 pounds per square inch – gauge (psig). However, by using the setpoint calculation methodology of 10 CFR Part 50, Appendix G, the resulting LTOP setpoint was calculated to be 420 psig. Therefore, the 500 psig setpoint was found to be non-conservative and the LTOP systems were declared inoperable. As part of its corrective actions, the licensee revised the LTOP setpoints from 500 psig to 420 psig and made changes to operating procedures to delineate the acceptable operating conditions of the reactor coolant pumps and charging pumps during low temperature conditions.

  The finding was determined to be more than minor because the finding was associated with the human performance attribute of the Barrier Integrity Cornerstone and affected the cornerstone objective of providing reasonable assurance that physical design barriers, such as containment, protect the public from radionuclide releases caused by accidents or events. Specifically, the non-conservative LTOP setpoint provided reasonable doubt that the integrity of the RCS pressure boundary would be maintained during low temperature conditions. The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, “Significance Determination Process,” Attachment 0609.04, “Phase 1 - Initial Screening and Characterization of Findings,” Table 4a for the Barrier Integrity Cornerstone, dated January 10, 2008. The inspectors determined that the finding was of very low safety significance (Green) because all of the questions in the containment barrier column of Table 4a were answered NO and the actual setpoint of the power operated relief valves was 415 psig, below the revised LTOP setpoint. The inspectors also determined that the finding has a cross-cutting aspect in the area of problem identification and resolution, corrective action program component, because personnel did not use a low threshold for identifying issues [P.1(a)]. (Section 4OA3.1)

- Green. The inspectors identified a finding of very low safety significance and associated Severity Level IV NCV of Technical Specification 5.6.5(c), “Reactor Coolant System Pressure and Temperature Limits Report (PTLR),” for the failure to submit a revised PTLR to the NRC for a new fluence period. Specifically, TS 5.6.5(c) required the PTLR be provided to the NRC for each reactor fluence period. Based on the references in TS 5.6.5(b), the fluence period for revision 1 of the PTLR could not be extended past February 2004. The licensee inappropriately extended the existing PTLR applicability limit past this date and did not submit a revised PTLR as required. Corrective actions included submittal of the revised PTLR (revision 2) on November 15, 2007.

  This finding was determined to be more than minor because it was associated with the design control attribute of the Barrier Integrity Cornerstone and affected the cornerstone objective to provide reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. Specifically, the curve used to define plant operating limits for acceptable pressure and temperature conditions for protection against failure of the reactor vessel was not valid after February 2004. The finding is not suitable for SDP evaluation under the Barrier Integrity Cornerstone, but has been reviewed by NRC management and is determined to be a finding of very low safety significance. Specifically, subsequent calculations using an NRC approved methodology determined that the Point Beach Unit 1 reactor vessel was not outside of the safety limits and was fully capable of performing the required service. The inspectors determined that the finding does not have an associated cross-cutting aspect. (Section 4OA5.1)

Cornerstone: Public Radiation Safety

- Green. The inspectors identified a finding of very low safety significance and an associated NCV of TS 5.4.1 for the failure to establish written procedures to implement the radioactive effluent control program as provided in the Offsite Dose Calculation Manual to ensure effluent sample analyses satisfied required detection criteria. Specifically, no process was established to ensure that effluent analysis capabilities for chemistry analytical equipment were periodically demonstrated to meet required lower levels of detection (LLDs). As corrective actions, the licensee subsequently performed LLD determinations for its analytical equipment (gamma spectroscopy system) and developed procedures to ensure LLDs were periodically verified consistent with industry standards.

The finding was determined to be more than minor because it affected the program and process attribute of the Public Radiation Safety Cornerstone and affected the cornerstone objective of ensuring adequate protection of public health and safety from exposure to radioactive material released into the public domain. Specifically, given the instability in the licensee’s gamma spectroscopy system since 2007, as evidenced by repetitive performance check failures, the ability of the equipment to achieve required LLDs could have been impacted or necessitated changes in analysis parameters (such as count times) resulting in non-conservative effluent quantification. The inspectors determined that the finding was of very low safety significance (Green) because it did not represent a substantial failure to implement the effluent release program or result in public dose that exceeded specified criterion. The inspectors also determined that the finding has a cross-cutting aspect in the area of human performance, resources component, in that the licensee failed to develop procedures to fully implement its effluent program as provided in the Offsite Dose Calculation Manual (ODCM) [H.2(c)]. (Section 2PS1.2)

B. Licensee-Identified Violations

None.

REPORT DETAILS

Summary of Plant Status

Unit 1 was at 100 percent power at the beginning of the inspection period, shut down to commence the cycle 31 refueling outage (U1R31) on October 6, 2008, restarted on November 12, and returned to 100 percent power on November 18. Unit 1 remained at or near 100 percent power for the remainder of the inspection period with the exception of planned reductions in power during routine auxiliary feedwater (AFW) pump and secondary system valve testing.

Unit 2 was at 100 percent power throughout the entire inspection period with the exception of a planned reduction in power during routine AFW testing and a planned downpower to 66 percent on December 6, 2008, during turbine trip and condenser steam dump testing.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

The inspectors performed partial system walkdowns of the following risk-significant systems:

- residual heat removal (RHR) system while in Mode 6, and
- spent fuel pool cooling (SFPC) system while full core off-loaded into pool.

The inspectors selected these systems based on their risk-significance relative to the Reactor Safety Cornerstones at the time they were inspected. The inspectors attempted to identify any discrepancies that could impact the function of the system, and, therefore, potentially increase risk. The inspectors reviewed applicable operating procedures, system diagrams, the Final Safety Analysis Report (FSAR), Technical Specification (TS) requirements, outstanding work orders (WOs), condition reports, and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have rendered the systems incapable of performing their intended functions. The inspectors also walked-down accessible portions of the systems to verify system components and support equipment were aligned correctly and operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious deficiencies. The inspectors also verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the CAP with the appropriate significance characterization. Documents reviewed are listed in the Attachment.

These activities constituted two partial system walkdown samples as defined in Inspection Procedure (IP) 71111.04-05.

b. Findings

No findings of significance were identified.

.2 Semi-Annual Complete System Walkdown

a. Inspection Scope

During the week November 17, 2008, the inspectors performed a complete system alignment inspection of the G-05 gas turbine generator 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, temperature indications, component labeling, component lubrication, component and equipment cooling, hangers and supports, functionality of support systems, and to ensure that ancillary equipment or debris did not interfere with equipment operation. A review of a sample of past and outstanding WOs was performed to determine whether any deficiencies significantly affected the system function. In addition, the inspectors reviewed the CAP database to ensure that any system equipment alignment problems were being identified and appropriately resolved. Documents reviewed are listed in the Attachment.

These activities constituted one complete system walkdown sample as defined in IP 71111.04-05.

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 that were focused on availability, accessibility, and the condition of firefighting equipment in the following risk-significant plant areas:

- fire zone 681: G-05 gas turbine generator building;
- fire zone 304S: AFW pump room south section;
- fire area A36: Unit 1 containment;
- fire area A01-A: Unit 1 primary auxiliary building – 8' elevation;
- fire area A01-G: Unit 1 façade; and
- fire zones 770/775: G-03/G-04 diesel generator rooms.

The inspectors reviewed areas to assess if the licensee had implemented a fire protection program that adequately controlled combustibles and ignition sources within the plant, effectively maintained fire detection and suppression capability, maintained passive fire protection features in good material condition, and had implemented adequate compensatory measures for out-of-service, degraded, or inoperable fire protection equipment, systems, or features in accordance with the licensee's fire plan. The inspectors selected fire areas based on their overall contribution to internal fire risk and their potential to impact equipment which could initiate or mitigate a plant transient. Using the documents listed in the Attachment, the inspectors verified that fire hoses and extinguishers were in their designated locations and available for immediate use; that fire detectors and sprinklers were unobstructed; that transient material loading was within the analyzed limits; and fire doors, dampers, and penetration seals appeared to be in satisfactory condition. The inspectors also verified that minor issues identified during the inspection were entered into the licensee's CAP. Documents reviewed are listed in the Attachment to this report.

These activities constituted six quarterly fire protection inspection samples as defined in IP 71111.05-05.

b. Findings

No findings of significance were identified.

1R07 Annual Heat Sink Performance (71111.07)

.1 Heat Sink Performance

a. Inspection Scope

The inspectors reviewed the licensee's inspection results of the Unit 1 containment accident fans to verify that potential deficiencies did not mask the licensee's ability to detect degraded performance, 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 or that would cause an increase in risk. The inspectors reviewed the licensee's observations as compared against acceptance criteria.

This annual heat sink performance inspection constituted one sample as defined in IP 71111.07-05.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08)

.1 Piping Systems Inservice Inspection (ISI)

a. Inspection Scope

From October 6 through October 24, 2008, the inspectors conducted a review of the implementation of the licensee's Risk-Informed Inservice Inspection Program for monitoring degradation of the RCS boundary and the risk-significant piping system boundaries. The inspectors selected program components and American Society of Mechanical Engineers (ASME) Code Section XI required examinations and Code components in order of risk priority, as identified in Section 71111.08-03 of the inspection procedure, based upon the ISI activities available for review during the onsite inspection period.

The inspectors observed and performed a record review of the following two types of non-destructive examination (NDE) activities to evaluate compliance with the ASME Code Section XI and Section V requirements and to verify that indications and defects (if present) were dispositioned, in accordance with the ASME Code Section XI requirements or an NRC-approved alternative (e.g., an approved relief request).

- ultrasonic examination (UT) of RHR heat exchanger ‘B’ shell-to-head weld, RHR-B-1, and shell-to-flange weld, RHR-B-2;
- VT of component supports, RHR-B-LEG-1 through 4, on the “B” RHR heat exchanger;
- VT of flange bolting, CVC-02-PSI-1002-35-FB, on the “B” loop of the chemical and volume control (CVC) system; and
- VT of valve bolting, 1-SI-867B-BLT, on safety injection (SI) valve 1SI-867B.

The inspector reviewed documentation for examinations completed during the previous outage with relevant/recordable conditions/indications that were accepted for continued service to verify that the licensee’s acceptance was in accordance with the Section XI of the ASME Code. Specifically, the inspector reviewed the following records:

- indication disposition reports resulting from VT of SI system supports, SI-301R-1-H8 and SI-1051R-1-H3, where the spring can load setting was not as shown on the drawing. The engineering evaluation calculated the as-found settings as acceptable; and
- indication disposition report of AFW system valve weld AF-03-AFW-1002-2. The indications were measured to be less than 1/64-inch in diameter and therefore within the Code acceptance criterion.

The inspectors reviewed pressure boundary welds for Class 1 and 2 systems that were completed since the beginning of the previous refueling outage. The inspectors also reviewed the work order and welding documents for a Class 2 pressure boundary weld to be completed in the U1R31. As applicable, the inspection was performed to determine if the welding acceptance and preservice examinations (e.g., weld procedure qualification tensile tests, VT, and dye penetrant) were performed in accordance with ASME Code Sections III, V, IX, and XI requirements. Specifically, the inspectors reviewed welds associated with the following work activities:

- repair/replacement (welding) of ASME Class 2 coupling on 2-SI-301R-3 piping from the containment spray pump discharge to the addition tank; and
- repair/replacement (welding) of ASME Class 2 valve CV-303B, seal injection filter 1F-39B inlet.

This inspection in combination with those described in report sections 1R08.2 through 1R08.5, constituted one inspection sample as defined in IP 71111.08. The documents reviewed during this inspection are listed in the Attachment.

b. Findings

No findings of significance were identified.

.2 Pressurized Water Reactor Vessel Upper Head Penetration Inspection Activities

a. Inspection Scope

For the vessel head, no examination was required pursuant to NRC Order EA-03-009 during the U1R31. Therefore, no NRC review was conducted for this inspection procedure attribute.

b. Findings

No findings of significance were identified.

.3 Boric Acid Corrosion Control ISI

a. Inspection Scope

The inspectors observed licensee boric acid corrosion control visual examinations (VTs) for portions of the systems containing primary coolant water inside containment to determine if these VTs emphasized locations where boric acid leaks can cause degradation of safety-significant components.

The inspectors reviewed the following licensee evaluations of reactor coolant system (RCS) components with boric acid deposits and evaluated corrective actions for any degraded RCS components to determine if they met the component Construction Code and ASME Boiler and Pressure Vessel Code Section XI requirements:

- boric acid evaluation, 07-0194, 1CV-371B, letdown line containment isolation;
- boric acid evaluation, 07-0223, 1SC-966C, RCS hot-leg sample; and
- boric acid evaluation, 08-0059, 1SI-860B, P-14A containment spray pump discharge isolation.

The inspectors reviewed the following corrective action documents related to boric acid leakage to determine if the corrective actions completed were consistent with the requirements of the ASME Code Section XI and 10 CFR Part 50, Appendix B, “Quality Assurance for Nuclear Power Plants and Fuel Reprocessing Plants”:

- action request (AR) 01119055, significant boric acid found on 1SC-959;
- AR 01120405, boric acid on 1FT-173; and
- AR 01132026, active boric acid leak on 1GS-14.

b. Findings

Failure to Perform Evaluations of Boric Acid Leaks

Introduction: The inspectors identified a finding of very low safety significance and associated Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” for the failure to evaluate boric acid leaks as required by the Boric Acid Leakage and Corrosion Monitoring (BALCM) program.

Description: The licensee’s BALCM program requires that when a boric acid indication has been identified by other than a procedural exam, i.e., a leak test, a work request is to be written. In all boric acid indication cases reviewed by the inspectors, an AR existed which included a work request as its corrective action. Per BALCM program requirements, the work request shall be flagged as a boric acid leak for proper disposition and tracking. A boric acid evaluation was then required to be performed by the BALCM program engineer, based on flagged work orders, to identify work tasks associated with the leak and record them on form PBD-7051. The only exception to this requirement, was when the boric acid leak was characterized as dry, white and light, was contained within the packing gland area, and did not affect any bolting, and the boric acid crystals did not extend more than ¼-inch from the surface of the component. The BALCM program engineer then tracks completion of the recommended disposition to ensure the actions were taken.

During the inspectors' review of AR 1120405, written for a boric acid leak on 1PT-173, reactor coolant pump 1A seal differential pressure transmitter (a safety-related RCS pressure boundary piece of equipment), the inspectors identified that a boric acid evaluation was not performed in accordance with the BALCM program. Although the licensee had identified this procedure noncompliance and documented it in AR 1129052, the inspectors identified that the resolution of the AR did not provide an adequate extent of condition evaluation for the procedure compliance aspect of the issue.

This boric acid leak was observed during a non-ASME inspection; therefore, the inspectors reviewed an additional sample of ARs generated for boric acid leaks resulting from non-ASME observations from the previous two year period. The inspectors subsequently identified six additional ARs that described boric acid leaks on safety-related, ASME Section XI pressure boundaries, for which boric acid evaluations were not performed.

<u>Analysis</u>: The inspectors determined that the failure to perform evaluations on boric acid leaks was contrary to the BALCM Program and was a performance deficiency. Specifically, boric acid leakage at seven safety-related, ASME Code piping pressure boundaries was entered into the CAP but an engineering evaluation by the boric acid engineer was not performed as required by the BALCM.

This finding was determined to be more than minor in accordance with Inspection Manual Chapter (IMC) 0612, Appendix B, "Issue Screening," dated December 4, 2008, because it was associated with the human performance attribute of the Initiating Events Cornerstone and affected the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, boric acid leakage has historically been found to degrade carbon steel components affecting the RCS pressure boundary as well as the pressure boundary of components in emergency core cooling system (ECCS). This degradation, if not adequately evaluated, could lead to further leakage and result in plant operational changes (e.g., unplanned mode changes) or could impact the reliability of systems required for safe shutdown.

The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," Attachment 4, "Phase 1 - Initial Screening and Characterization of Findings," Table 4a for the Initiating Events Cornerstone, dated January 10, 2008. The finding was determined to be of very low safety significance (Green) because the issue did not result in exceeding the TS limit for identified RCS leakage nor did it affect other mitigating systems, resulting in a loss of their safety function.

This finding has a cross-cutting aspect in the area of human performance, work practices component, because the licensee did not effectively communicate expectations regarding procedural compliance and personnel following procedures. Specifically, the failure to perform evaluations on boric acid leaks was contrary to the BALCM program and providing clear expectations for procedure adherence and use would have prevented the non-compliance. [H.4(b)]

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings" requires, in part, that activities affecting quality be prescribed by documented instructions, procedures, and drawings, of a type appropriate to the circumstances and be accomplished in accordance with these instructions, procedures, or drawings. Licensee procedure NP 7.4.14, "Boric Acid Leakage and Corrosion Monitoring," required that each work request generated for boric acid leakage exceeding the specified criteria would have a boric acid evaluation performed.

Contrary to the above, during 2007 and 2008, the licensee failed to accomplish the requirements of the BALCM program in accordance with established procedures. Specifically, the licensee failed to perform at least seven boric acid leak evaluations for boric acid leaks identified in the CAP that exceeded the leakage criteria in the BALCM procedure. However, because this issue was determined to be of very low safety significance (Green) and was entered into the licensee's CAP as AR 1138361, this violation is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy. (NCV 05000266/2008005-01)

The licensee entered this issue into its CAP and was evaluating corrective actions at the end of the inspection period.

.4 Steam Generator (SG) Tube Inspection Activities

a. Inspection Scope

From October 13 through October 24, 2008, the inspectors performed an onsite review of Unit 1 SG tube examination activities, conducted pursuant to TS, and the ASME Code Section XI requirements. The NRC inspectors observed acquisition of eddy current (EC) data, interviewed EC data analysts, and reviewed documents related to the SG ISI program, and determined:

- in-situ SG tube pressure testing screening criteria and the methodologies used to derive these criteria were consistent with the Electric Power Research Institute (EPRI) TR-107620, "Steam Generator In-Situ Pressure Test Guidelines";
- the numbers and sizes of SG tube flaws/degradation identified were bound by the licensee's previous outage operational assessment predictions;
- the SG tube EC examination scope and expansion criteria were sufficient to identify tube degradation based on site and industry operating experience by confirming that the EC scope completed was consistent with the licensee's procedures, plant TS requirements and EPRI 1003138, "Pressurized Water Reactor Steam Generator Examination Guidelines," Revision 6;
- the licensee did not identify new tube degradation mechanisms;

- the SG tube EC examination scope included tube areas which represent EC challenges such as the tube sheet regions, expansion transitions, and support plates;
- the licensee implemented repair methods, which were consistent with the repair processes allowed in the plant TS requirements;
- the required repair criteria were being adhered to;
- the licensee primary-to-secondary leakage (e.g., SG tube leakage) was below the detection threshold during the previous operating cycle;
- the EC probes and equipment configurations used to acquire data from the SG tubes were qualified to detect the known/expected types of SG tube degradation in accordance with Appendix H, "Performance Demonstration for Eddy Current Examination," of EPRI 1003138, "Pressurized Water Reactor Steam Generator Examination Guidelines," Revision 6;
- where practicable, attempts were made to retrieve foreign objects. For those objects that were unable to be retrieved, evaluations were performed for the potential detrimental affects of the objects, and appropriate repairs of the affected tubes were planned/taken; and
- licensee-identified deviations from EC data acquisition or analysis procedures were appropriate.

The documents reviewed during this inspection are listed in the Attachment.

b. Findings

No findings of significance were identified.

.5 Identification and Resolution of Problems

The inspectors reviewed ISI/SG-related problems that were identified by the licensee and entered into the CAP, interviewed licensee staff, and reviewed licensee corrective action records to determine if the licensee had:

- described the scope of the ISI/SG related problems;
- established an appropriate threshold for identifying issues;
- evaluated operating experience and industry generic issues related to ISI and pressure boundary integrity; and
- implemented appropriate corrective actions.

The inspectors performed these reviews to ensure compliance with 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements. The corrective action documents reviewed by the inspectors are listed in the Attachment.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Examination Security

a. Inspection Scope

The inspectors reviewed a licensee's Action Request Record Report related to examination physical security (e.g., access restrictions) to verify compliance with 10 CFR 55.49, "Integrity of examinations and tests." The inspectors also reviewed the facility licensee's examination security procedure and any corrective actions related to past or present examination security problems at the facility. The documents reviewed during this inspection are listed in the Attachment.

This review did not constitute a sample as defined in IP 71111.11.

b. Findings

During a review of licensed operator examination security, the facility discovered that some operations instructors had unintentional access to keys for exam areas for which they were not authorized to have unrestricted access. This was not allowed by licensee procedure FP-T-SAT-71, NRC Exam Security Requirements. Interviews by training department management of these instructors revealed no one accessed examination secure materials. Additionally, a second barrier (additional keys and security passwords) had been in-place during the time of the unintentional access that would have prevented any unauthorized access to licensed operator examination materials. Therefore, no violation of examination integrity occurred. The training department documented the deficiency in examination room key control in the CAP in AR 01137883.

.2 Resident Inspector Quarterly Review (71111.11Q)

a. Inspection Scope

On December 8, 2008, the inspectors observed a crew of licensed operators in the plant's simulator during licensed operator simulator 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 training program objectives. Documents reviewed are listed in the Attachment.

This inspection constituted one quarterly licensed operator requalification program sample as defined in IP 71111.11.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations (71111.12Q)

a. Inspection Scope

The inspectors evaluated degraded performance issues involving the following risk-significant systems:

- service air system; and
- Unit 1 SI system.

The inspectors reviewed and independently verified the licensee's actions to address problems with system performance or condition in terms of the following:

- implementing appropriate work practices;
- identifying and addressing common cause failures;
- scoping of systems in accordance with 10 CFR 50.65(b) of the maintenance rule;
- characterizing system reliability issues for performance;
- charging unavailability for performance;
- trending key parameters for condition monitoring;
- ensuring 10 CFR 50.65(a)(1) or (a)(2) classification or re-classification; and
- verifying appropriate performance criteria for structures, systems, and components/functions classified as (a)(2) or appropriate and adequate goals and corrective actions for systems classified as (a)(1).

The inspectors assessed performance issues with respect to the reliability, availability, and condition monitoring of the system. In addition, the inspectors verified maintenance effectiveness issues were entered into the CAP with the appropriate significance characterization. Documents reviewed are listed in the Attachment.

This inspection constituted two quarterly maintenance effectiveness samples as defined in IP 71111.12-05.

b. Findings

No findings of significance were identified.

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

.1 Routine Quarterly Review

a. Inspection Scope

The inspectors reviewed the licensee's evaluation and management of plant risk for the planned maintenance and emergent work activities affecting risk-significant and safety-related equipment during the time periods listed below to verify that the appropriate risk assessments were performed prior to removing equipment for work during the weeks of:

- October 20;
- October 27;
- November 3;
- November 10; and
- December 22.

These work week activities were selected based on their potential risk-significance relative to the Reactor Safety Cornerstones. As applicable for each activity, the inspectors verified that risk assessments were performed as required by 10 CFR 50.65(a)(4) and were accurate and complete. When emergent work was performed, the inspectors verified that the plant risk was promptly reassessed and managed. The inspectors reviewed the scope of maintenance work, discussed the results of the assessment with the licensee's probabilistic risk analyst or shift technical advisor, and verified plant conditions were consistent with the risk assessment. The inspectors also reviewed TS requirements and walked-down portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid and applicable requirements were met. Documents reviewed are listed in the Attachment.

These maintenance risk assessments and emergent work control activities constituted five samples as defined in IP 71111.13-05.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- AR 01136629 – Unit 1 RHR system voiding (Generic Letter 08-01);
- AR 01138321 – boric acid degradation of Unit 1 A and B residual heat removal heat exchanger bolting;
- AR 01139923 – leading edge flow meter electrical signal noise issues; and
- AR 01140867 – south service water header service water pump reduction in flow.

The inspectors selected these potential operability issues based on the risk-significance of the associated components and systems. The inspectors evaluated the technical adequacy of the evaluations to ensure that TS operability was properly justified and the subject component or system remained available such that no unrecognized increase in risk occurred. The inspectors compared the operability and design criteria in the appropriate sections of the TSs and FSAR to the licensee's evaluations, to determine whether the components or systems were operable. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures in place would function as intended and were properly controlled. The inspectors determined, where appropriate, compliance with bounding limitations associated with the evaluations. Additionally, the inspectors also reviewed a sampling of corrective action documents to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations. Documents reviewed are listed in the Attachment.

This operability inspection constituted four samples as defined in IP 71111.15-05.

b. Findings

No findings of significance were identified.

1R18 Plant Modifications (71111.18)

.1 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed the following temporary modification:

- Unit 1 steam generator chemical cleaning system used during U1R31.

The inspectors compared the temporary configuration changes and vendor system design documents against the design basis, the FSAR, and the TSs, as applicable, to verify that the modification did not affect the operability or availability of the affected systems. The inspectors performed field verifications to ensure that the modification was installed as directed; the modification operated as expected; that process monitoring adequately demonstrated that no degradation to system materials occurred; and that operation of the modification did not impact the operability of any interfacing systems. Lastly, the inspectors discussed the temporary modification with vendor and operations personnel to ensure that the individuals were aware of expected actions in the event of a system failure or malfunction.

This inspection constituted one temporary modification sample as defined in IP 71111.18-05.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19)

.1 Post-Maintenance Testing

a. Inspection Scope

The inspectors reviewed the following Unit 1 post-maintenance activities to verify that procedures and test activities were adequate to ensure system operability and functional capability:

- containment polar crane bolt replacement;
- RHR trains A and B testing following system outages;
- ECCS common suction line following maintenance;
- SI valves SI-850A and B;

- high and low head SI test following 1-SI-867B check valve repair;
- Unit 1 SI pump 1P-15A overhaul; and
- Unit 1 turbine-driven AFW pump 1P-29.

These activities were selected based upon the structure, system, or component's ability to impact risk. The inspectors evaluated these activities for the following (as applicable): the effect of testing on the plant had been adequately addressed; testing was adequate for the maintenance performed; acceptance criteria were clear and demonstrated operational readiness; test instrumentation was appropriate; tests were performed as written in accordance with properly reviewed and approved procedures; equipment was returned to its operational status following testing; and test documentation was properly evaluated. The inspectors evaluated the activities against the TSs, the FSAR, 10 CFR Part 50 requirements, licensee procedures, and various NRC generic communications to ensure that the test results adequately ensured that the equipment met the licensing and design bases. In addition, the inspectors reviewed corrective action documents associated with post-maintenance tests to determine whether the licensee was identifying problems and entering them in the CAP and that the problems were being corrected commensurate with their importance to safety. Documents reviewed are listed in the Attachment.

This inspection constituted seven post-maintenance testing sample as defined in IP 71111.19-05.

b. Findings

No findings of significance were identified.

1R20 Outage Activities (71111.20)

.1 Draindown of RCS in Pressurizer With Inaccurate Level Indication

a. Inspection Scope

The inspectors reviewed the circumstances surrounding the October 8, 2008, draindown of the Unit 1 RCS from a solid plant condition to approximately 67 percent pressurizer level, whereby the pressurizer level instrumentation did not respond. The inspectors reviewed licensee documentation, interviewed licensee personnel and management in operations and maintenance, and reviewed previous failures of the pressurizer level instrumentation to respond appropriately during RCS draindowns. Documents reviewed are listed in the Attachment to this report.

b. Findings

Introduction: A finding of very low safety significance and associated NCV of 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” was self-revealed for the failure to have procedures appropriate to the circumstances for the draindown of the RCS from a solid plant condition. Specifically, procedure OP-4D, “Draining the Reactor Coolant System,” did not require that the pressurizer level instrumentation reference line be filled within a defined period of time to ensure that the pressurizer level instrumentation functioned properly prior to draining the RCS. This resulted in the licensee draining approximately 2,000 gallons of RCS inventory from the pressurizer without a valid control room indication of pressurizer level.

Description: On October 8, 2008, control room operators commenced draining reactor coolant from the pressurizer as a part of the normal progression towards refueling mode for U1R31. The RCS was in a solid condition (greater than 100 percent indicated level) and the operators were draining the RCS to approximately 25 percent indicated level. At approximately 12:30 p.m. the operators established an initial draindown of 1,200 gallons to ensure that level instrumentation came on scale and responded appropriately. After draining approximately 1,200 gallons, verified by the established drain rate and the non-safety-related hold-up tank "C" level indications, the operators suspended the draindown to address inventory balances and ensure indicators were functioning properly. The control room pressurizer cold calibration level transmitter LT-433 had not come on-scale (it should have come on-scale after about 900 gallons were drained) and the operations department managers decide that a valve lineup verification would be performed to confirm the physical lineup of the system. The valve lineup was performed satisfactorily with no discrepancies noted and the inventory balances were again compared and verified to the hold-up tank "C" level. Operations management then decided to continue draining an additional 30 minutes (approximately 800 gallons) for a total of 2,000 gallons. Following this additional inventory reduction, the draindown was suspended to address the inventory balances and pressurizer level indicator response. The operators verified that the control room pressurizer level transmitter still had not responded to the additional RCS reduction.

Instrumentation and control technicians were then requested to perform Attachment I of operations procedure OP-4D Part 1, "LT-433, T-1 Pressurizer Cold Calibration Level Transmitter Reference Line Fill." Upon completion of the filling of the reference line, pressurizer level transmitter LT-433 indicated 67 percent pressurizer level in the control room and on the plant process computer, which correlated to the 3 percent rise in level seen in hold-up tank "C," a volume of approximately 2,000 gallons. The licensee initiated condition report 1137061 for this self-revealed instrumentation failure, which was assigned a "B" significance level and a condition evaluation.

Upon review of the completed condition evaluation in October 2008, the inspectors noted that the evaluation may not have identified the appropriate cause for the failure of the instrument to respond. The inspectors based this assessment on the past failures of the level transmitter in the fall of 2006 and spring of 2004, and that the evaluation focused on the procedure not quantifying expected instrument responses based on inventory reductions. The inspectors noted that an apparent cause evaluation conducted for the fall of 2006 failure identified that the reference line had emptied causing an erratic instrument response. While the 2006 corrective actions required performance of Attachment I of procedure OP-4D prior to the start of the draindown, the time critical nature of this activity was not translated from the apparent cause evaluation into the corrective action for the procedure change. The inspectors reviewed the October 2008 control room logs and determined that Attachment I of procedure OP-4D had been performed on October 7, 2008, over 25 hours prior to the start of the draindown. The licensee's 2006 apparent cause evaluation had concluded that Attachment I should be performed as soon as possible before beginning the draindown but no more than about 4 hours prior to the start. The inspectors also determined that a delay in the outage schedule had caused the large amount of time to elapse from performance of Attachment I of procedure OP-4D and the actual RCS draindown.

The licensee evaluated the additional information provided by the inspectors and concluded that an apparent cause evaluation was warranted. The licensee concluded in the apparent cause that previous attempts to correct the problems with the reference line of pressurizer level transmitter LT-433 with procedure OP-4D were ineffective to address the timeliness aspect of filling the reference line commensurate with draindown.

Analysis: The inspectors determined that the failure to have a procedure appropriate to the circumstances to conduct RCS draindowns with properly functioning level instrumentation was a performance deficiency. The finding was determined to be more than minor in accordance with IMC 0612, Appendix B, “Issue Screening,” dated December 4, 2008, because the finding was associated with the Mitigating Systems Cornerstone attribute of operating procedure quality 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). Specifically, the pressurizer level instrumentation is utilized during shutdowns to detect and manually initiate mitigating actions for uncontrolled RCS inventory reductions.

The inspectors determined that the finding could be evaluated in accordance with IMC 0609, Appendix G, “Shutdown Operations SDP,” dated February 28, 2005. The inspectors used Checklist 2 contained in Attachment 1 and determined that the finding required a Phase 2 analysis since the finding increased the likelihood of loss of RCS inventory based on level deviation in the control room (Section II.A.of Checklist 2).

The Region III senior reactor analyst (SRA) performed the assessment using Appendix G, Attachment 2, "Phase 2 Significance Determination Process Template for PWR during Shutdown." The SRA determined this to be a precursor to an initiating event (a loss of level control precursor - LOLC). The plant operating state (POS) was determined to be "POS 1" (vessel head on and RCS closed). The initiating event likelihood for LOLC using Table 1, "Initiating Event Likelihood (IELs) for LOLC Precursors" was one, since the time to RHR loss was greater than two hours and action to recover RHR could be identified and performed within half of the time to RHR loss. The SRA considered this to be an overly conservative value considering that the operators stopped draining at 67 percent pressurizer level to perform further evaluation. To better estimate the IEL, the SRA performed an analysis using the SPAR-H Human Reliability Analysis Method, NUREG/CR-6883, September 2004.

For diagnosis of potential LOLC, the analyst assumed stress to be high and available time to be expansive. For action, the analyst assumed stress to be high. All other performance shaping factors were assumed to be nominal. The resultant value of 2.2E-3 was assumed as the initiating event likelihood.

Using Appendix G, Attachment 2, Worksheet 1, "SDP for a PWR Plant - Loss Level Control in POS 1 (RCS Closed)," the analyst evaluated the remaining mitigating capability credit to reflect equipment availability and the time available to complete tasks prior to core damage. The most significant core damage sequences involved loss of steam generator cooling and failure of RCS injection and bleed before core damage. The combined sequences had a risk-significance of about 2.2E-8. Therefore, the SRA determined that this issue is best characterized as a finding of very low safety significance (Green).

This finding has a cross-cutting aspect in the area of problem identification and resolution, corrective action program, because the licensee failed to take appropriate corrective actions to address safety issues and adverse trends associated with the pressurizer level instrumentation in a timely manner, commensurate with their safety significance and complexity. [P.1(d)]

Enforcement: 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality be prescribed by documented instructions or procedures of a type appropriate to the circumstances.

Contrary to the above, on October 8, 2008, the licensee commenced draining the RCS from a solid plant condition, an activity affecting quality, with a procedure which was not appropriate to the circumstances. Specifically, procedure OP-4D, "Draining the Reactor Coolant System," did not adequately prescribe the timeliness aspect of filling the reference line of the pressurizer level transmitter commensurate with the draindown, consequently the draindown was performed without accurate pressurizer level indication in the control room. Because this violation was of very low safety significance and it was entered into the licensee's CAP as AR 01137061, this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 05000266/2008005-02).

In response to this issue, the licensee performed an apparent cause evaluation and initiated corrective actions to: correct the deficient procedure conditions; add additional information regarding expected instrument response for a given volume of reactor coolant removed from the system; and establish an initial quantified volume to begin the draindown, followed by prescribed corrective actions to take if level instrumentation did not respond appropriately. Also, the operating crews were coached regarding documentation of intermediate decisions and stopping points in station logs and additional lessons learned were reviewed with the operations crews.

.2 Non-Conformances Identified with Safety-Related Sump Screen Debris Interceptors

a. Inspection Scope

The inspectors performed the final containment walkdown for boric acid deposits and safeguards system readiness while Unit 1 was in Mode 3 and normal operating temperature and pressure. During the walkdown, the inspectors noted that the recently modified containment sump screen debris interceptors did not conform to the original design as detailed in the engineering change package. The inspectors reviewed the engineering change package and associated 50.59 evaluation, and interviewed licensee staff responsible for the modification to the safety-related sump screen, which was made during U1R31.

b. Findings

Introduction: The inspectors identified a finding of very low safety significance and associated NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," for the failure to appropriately implement work orders for the installation of the Z-296-B3 containment sump screen debris interceptor. As a result, this portion of the modification was not installed as designed when the modification was completed during the refueling outage and the Unit 1 reactor transitioned to Mode 3.

Description: As a result of the resolution of NRC Generic Letter 2004-02 ("Potential Impact of Debris Blockage on Emergency Recirculation During Design Basis Accidents at Pressurized-Water Reactors") and Generic Safety Issue GSI-191 ("Assessment of Debris Accumulation on PWR [Pressurized-Water Reactor] Sump Performance"), the licensee was required to modify the emergency core cooling system sump. In a previous refueling outage, the licensee had installed new emergency core cooling system sump screens which had a significantly larger area than the originally installed screens. However, testing performed during the summer of 2008 demonstrated that additional capture of the debris was required in order to meet the test acceptance criteria with the new sump screens. Consequently, the licensee designed two types of debris interceptors in engineering change 12604 to be installed around the new sump screens. The "B" type debris interceptors were installed on the 10-foot steam generator platforms and consisted of perforated plate with ¼-inch gaps. In addition, the design contained a requirement that the maximum allowable gap between the debris interceptor perforated plate and the concrete cubicle walls was also limited to ¼-inch. On October 29, 2008, the installation of the "B" type debris interceptors was completed by the licensee personnel performing the installation. On November 6, 2008, a final engineering staff walkdown was completed of the installed modification. On November 10, 2008, the Unit 1 reactor was transitioned to Mode 3 at normal operating temperature and pressure.

On November 11, 2008, the inspectors performed a final Mode 3 walkdown to verify that there were no boric acid leaks and to ensure the systems inside containment were ready for power operation. The inspectors noted that the Z-296-B3 debris interceptor and the adjacent concrete wall on the west side had a gap which exceeded the allowable ¼ inch and was estimated at approximately ½ inch, approximately 2/3 of the length of the debris interceptor.

The licensee initiated AR 01139651 and took remedial corrective actions to install the appropriate flashing to remove the gap. At the end of the inspection period, the licensee was performing an apparent cause evaluation to determine why the debris interceptor was not installed in accordance with the design documentation and why reviews performed by the licensee as part of the installation, failed to identify this issue.

Analysis: The inspectors determined that the failure to properly install the Z-296-B3 debris interceptor in accordance with documented work instructions and drawings as part of the containment sump modification was a performance deficiency. The finding was determined to be more than minor in accordance with IMC 0612, Appendix B, "Issue Screening," dated December 4, 2008, because the finding was associated with the Mitigating Systems Cornerstone attributes of initial modification design control and human performance, 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). Specifically, the debris interceptor is a passive device utilized to minimize the debris blockage on the emergency core cooling sump screens.

The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Phase 1 - Initial Screening and Characterization of Findings," Table 4a for the Mitigating Systems Cornerstone, dated January 10, 2008. The inspectors determined that the finding was of very low safety significance (Green) because the finding did not involve a design or qualification deficiency, did not represent an actual loss of safety function or a single train loss of safety function for greater than the TS-allowed outage time, and was not potentially risk-significant for external events.

This finding has a cross-cutting aspect in the area of human performance, work practices, because personnel work practices for the installation did not utilize the available human error prevention techniques, specifically self and peer checking, and the use of a questioning attitude. [H.4(a)]

Enforcement: 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” requires, in part, that activities affecting quality be accomplished in accordance with documented instructions, procedures or drawings.

Contrary to the above, prior to November 11, 2008, the licensee failed to properly install the Z-296-B3 debris interceptor in accordance with the documented instructions and drawings, an activity affecting quality. Specifically, the debris interceptor was installed with one side of the debris interceptor against the containment 10-foot platform wall having a gap greater than the maximum allowed ¼-inch, specified in the instructions and drawings contained in WO 360573. Because this violation was of very low safety significance and it was entered into the licensee’s CAP as AR 01139651, this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 05000266/2008005-03).

In response to this issue, the licensee initiated remedial corrective actions to correct the non-conforming condition. In addition, at the end of the inspection period, the licensee was performing an apparent cause evaluation which likely would result in additional corrective actions.

.3 Inadequate Inspection Procedure for Containment Polar Crane Structures

a. Inspection Scope

The inspectors reviewed the circumstances surrounding the failure of a bolt on the Unit 1 containment polar crane that was discovered on October 16, 2008, during U1R31. The inspectors observed the licensee’s failure investigation process and observed a number of licensee meetings. The inspectors reviewed the current licensing and design bases documents for the polar cranes of both Units and their support structures, and reviewed the licensee’s inspection procedures and documentation for previously performed polar crane inspections for their conformance with the requirements of 10 CFR Part 50, Appendix B.

b. Findings

Introduction: A finding of very low safety significance and associated NCV of 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” was self-revealed for the failure to have inspection procedures appropriate to the circumstances for the Unit 1 and Unit 2 containment polar cranes and their integral support structures. Specifically, station routine maintenance procedure 1(2) RMP 9118-1(2), “Containment Building Crane OSHA Operability Inspections,” did not provide adequate instruction to ensure that the polar crane lateral restraint bolts would be inspected for signs of degradation or movement, e.g., flaking paint or being backed out of position. As a result, improperly installed bolts went undiscovered by the licensee until a failed bolt was found lying on the containment floor, which revealed the crane's degraded condition.

Description: On October 16, 2008, during U1R31, the licensee discovered that a bolt from one of the Unit 1 containment polar crane support bracket lateral restraints, an extension of the containment structure, broke and fell to the containment floor below. The licensee immediately halted use of the crane, investigated the occurrence, and performed an extent-of-condition visual inspection of all other support locations. Additional licensee examination discovered that four of the other bolts at the affected support location were found loose due to improper installation. No other support locations were identified to be degraded. As a part of the licensee's investigation, engineering performed an evaluation of the as-found degraded condition of the polar crane support structure and determined that the crane load lifting capacity could be de-rated to 40 tons, from 100 tons, and small load lifts were allowed to resume. Following the extent-of-condition inspection, and once the affected bolts were replaced, the crane was returned to full rated capacity.

The licensee determined that the failure was most likely due to the improper initial installation of the bolt, which allowed the bolt to vibrate under normal at-power operational vibration conditions inherently present in containment, to the point of fatigue. With fatigue cracks present, the degraded bolt finally failed at some point during crane operation in which the crane bridge traversed the area over the support. The licensee employed the services of an outside vendor to perform a failure analysis of the failed bolt, which confirmed the licensee's initial conclusions. Photos taken of the other affected bolts clearly showed signs that they had moved from their initial position, as evidenced by flaked paint around the edge of the bolts. Fatigue cracks were also identified.

The licensee's current procedures for inspecting the polar cranes prior to their use, 1RMP 9118-1 and 2RMP 9118-2, "Containment Building Crane OSHA Operability Inspections," required a visual check of the crane's rail support "runway" for degradation. The "runway" was defined as the box girders supporting the rail; however, the particular bolting locations in question were never included in these inspections despite being a part of the "runway." As such, the licensee missed previous opportunities to identify and correct the loose, degraded bolts prior to the self-revealing failure of one bolt and the fatigue cracking of others. The licensee's apparent cause evaluation (AR 1137773) concluded that their inspection guidance was vague and insufficient with respect to the lateral restraint bolts in question.

Analysis: The inspectors determined that the failure to perform an adequate and thorough inspection of components critical to the safe operation of the containment polar crane system was a performance deficiency. The finding was determined to be more than minor in accordance with IMC 0612, Appendix B, "Issue Screening," dated December 4, 2008, because the finding was associated with the Initiating Events Cornerstone attribute of equipment performance and affected the cornerstone objective of limiting the likelihood of those events that challenge critical safety functions during shutdown. Specifically, the failure to visually inspect critical bolting locations on crane support structures could have allowed the polar crane to perform heavy load lifts, e.g., reactor vessel head assembly or upper internals lifts, with the crane in a degraded condition, increasing the likelihood of a support failure and subsequent load drop.

The inspectors determined that the finding could be evaluated in accordance with IMC 0609, Appendix G, "Shutdown Operations SDP," dated February 28, 2005. The inspectors used Checklist 4 contained in Attachment 1 and determined that the finding did not require a phase 2 or phase 3 analysis because the plant had appropriately met the safety function guidelines for core heat removal, inventory control, power availability, containment integrity, and reactivity control. The issue did not need a quantitative assessment and screened as Green using Figure 1.

This finding has a cross-cutting aspect in the area of human performance, resources, for the failure to have complete and accurate procedures in place. Specifically, the vague and insufficient detail in the crane inspection procedures contributed to the licensee's failure to perform an adequate inspection of crane components to identify degraded components prior to their failure. [H.2(c)]

Enforcement: Title 10 CFR Part 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 be accomplished in accordance with these instructions, procedures, or drawings.

Contrary to the above, before and during U1R31, the licensee failed to have in place procedures of a type appropriate to the circumstances for the polar crane inspections. Specifically, 1RMP 9118-1 and 2RMP 9118-2, "Containment Building Crane OSHA Operability Inspections," were inadequate to ensure that degraded crane structural components were identified through visual inspection prior to their degradation and failure. Because this violation was of very low safety significance and it was entered into the licensee's CAP as AR 1137773, this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 05000266/2008005-04; 05000301/2008005-04).

In response to this condition, the licensee repaired the affected components, performed an extent-of-condition inspection, and performed an apparent cause evaluation to identify the cause of the issue and formulated recommended corrective actions to address the procedural issues.

.4 Refueling Outage Activities

a. Inspection Scope

The inspectors observed activities during U1R31, conducted October 6 – November 12, 2008, to confirm that the licensee had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth. During U1R31, the inspectors observed portions of the shutdown and cooldown processes and monitored licensee controls over the outage activities listed below:

- licensee configuration management, including maintenance of defense-in-depth for key safety functions and compliance with the applicable TSs when taking equipment out-of-service;

- implementation of clearance activities and confirmation that tags were properly hung and equipment appropriately configured to safely support the work or testing;
- installation and configuration of reactor coolant pressure, level, and temperature instruments to provide accurate indication, accounting for instrument error;
- controls over the status and configuration of electrical systems to ensure that TS requirements were met, and controls over switchyard activities;
- monitoring of decay heat removal processes, systems, and components;
- controls to ensure that outage work was not impacting the ability of the operators to operate the spent fuel pool cooling system;
- reactor water inventory controls including flow paths, configurations, and alternative means for inventory addition, and controls to prevent inventory loss;
- controls over activities that could affect reactivity;
- maintenance of containment closure as required by TSs and the technical requirements manual;
- refueling activities, including fuel handling and sipping to detect fuel assembly leakage;
- startup and ascension to full power operation, tracking of startup prerequisites, walkdown of containment to verify that debris had not been left which could block ECCS suction strainers, and reactor physics testing; and
- licensee identification and resolution of problems related to the outage.

This inspection, in combination with those documented above in sections 1R20.1 and 1R20.2, constituted one refueling outage sample as defined in IP 71111.20-05.

b. Findings

No findings of significance were identified, other than those already described in sections 1R20.1 and 1R20.2.

1R22 Surveillance Testing (71111.22)

.1 Surveillance Testing

a. Inspection Scope

The inspectors reviewed the test results for the following activities to determine whether risk-significant systems and equipment were capable of performing their intended safety function and to verify testing was conducted in accordance with applicable procedural and TS requirements:

- IT 06 – Unit 2 containment spray pumps and valves quarterly test; (Inservice Testing—IST)
- RESP – 1.2 IPTE to adjust rod position indicators; (routine)
- IT 07D – P-32D service water pump quarterly test; (IST)
- Unit 1 ORT-3A – SI actuation with loss of all alternating current (Train A); (routine) and
- Unit 1 ORT-3B – SI Actuation with loss of all alternating current (Train B). (routine)

The inspectors observed in-plant activities and reviewed procedures and associated records to determine the following:

- did preconditioning occur;
- were the effects of the testing adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- were acceptance criteria clearly stated, demonstrated operational readiness, and 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 frequencies were in accordance with TSs, procedures, the FSAR, and other 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 inservice testing activities, testing was performed in accordance with the applicable version of ASME Code Section XI, and reference values were consistent with the system design basis;
- where applicable, test results not meeting acceptance criteria were addressed with an adequate operability evaluation or the system or component 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 CAP.

Documents reviewed are listed in the Attachment.

This inspection constituted three routine surveillance testing samples and two inservice testing samples, as defined in IP 71111.22, Sections -02 and -05.

b. <u>Findings</u>

No findings of significance were identified.

Cornerstone: Emergency Preparedness

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

.1 Emergency Action Level and Emergency Plan Changes

a. Inspection Scope

Since the last NRC inspection of this program area, Emergency Plan, Section 7.0 and Appendix A, Revisions 52 and 27, were implemented based on the licensee's determination, in accordance with 10 CFR 50.54(q), that the changes resulted in no decrease in effectiveness of the Plan, and that the revised Plan as changed continues to meet the requirements of 10 CFR 50.47(b) and Appendix E to 10 CFR Part 50. The inspectors conducted a sampling review of the Emergency Plan changes and a review of the Emergency Action Level changes to evaluate for potential decreases in effectiveness of the Plan. However, this review does not constitute formal NRC approval of the changes. Therefore, these changes remain subject to future NRC inspection in their entirety.

This emergency action level and emergency plan changes inspection constituted one sample as defined in IP 71114.04-05.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

.1 Plant Walkdowns and Radiation Work Permit (RWP) Reviews

a. Inspection Scope

The inspectors reviewed licensee controls and surveys in the following radiologically significant work areas within radiation areas, high radiation areas, and airborne radioactivity areas in the plant to determine if radiological controls including surveys, postings, and barricades were acceptable:

- Unit 2 containment building (general areas);
- Unit 2 containment keyway;
- primary auxiliary building (various areas);
- spent fuel pool area; and
- radioactive material storage yard.

This sample was credited and documented in Inspection Report 05000266/2008003; 05000301/2008003; therefore, this supplemental information does not represent a sample.

The inspectors reviewed the RWPs and work packages used to access these areas and other high radiation work areas. The inspectors assessed the work control instructions and control barriers specified by the licensee. Electronic dosimeter alarm setpoints for both integrated dose and dose rate were evaluated for conformity with survey indications and plant policy. The inspectors interviewed workers to verify that they were aware of the actions required if their electronic dosimeters noticeably malfunctioned or alarmed.

This inspection constitutes one complete sample as defined in IP 71121.01-5.

The inspectors assessed the adequacy of the licensee's internal dose assessment process for internal exposures in excess of 50 millirem committed effective dose equivalent. There were no internal exposures greater than 50 millirem committed effective dose equivalent for the period reviewed by the inspectors.

This inspection constitutes one complete sample as defined in IP 71121.01-5.

The inspectors also reviewed the licensee's physical and programmatic controls for highly activated and/or contaminated materials (non-fuel) stored within the spent fuel pool or other storage pools.

This inspection constitutes one complete sample as defined in IP 71121.01-5.

b. Findings

No findings of significance were identified.

.2 Job-In-Progress Reviews

a. Inspection Scope

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

- Unit 2 containment sump level indicator maintenance;
- Unit 2 containment floor plug removal activities;
- Unit 2 reactor vessel bare metal ISI; and
- Unit 2 reactor vessel liner ISI.

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

This inspection constitutes one complete sample as defined in IP 71121.01-5.

Job performance was observed with respect to the radiological control requirements to assess whether radiological conditions in the work area were adequately communicated to workers through pre-job briefings and postings. The inspectors evaluated the adequacy of radiological controls, including required radiation, contamination, and airborne surveys for system breaches; radiation protection job coverage, including any applicable audio and visual surveillance for remote job coverage; and contamination controls.

This inspection constitutes one complete sample as defined in IP 71121.01-5.

The inspectors reviewed radiological work in high radiation work areas having significant dose rate gradients to evaluate whether the licensee adequately monitored exposure to personnel and to assess the adequacy of licensee controls. These work areas involved areas where the dose rate gradients were potentially severe; thereby, increasing the necessity of providing multiple dosimeters or enhanced job controls.

This inspection constitutes one complete sample as defined in IP 71121.01-5.

b. Findings

No findings of significance were identified.

.3 High Risk Significant, High Dose Rate, High Radiation Area, and Very High Radiation Area Controls

a. Inspection Scope

The inspectors held discussions with the Radiation Protection Manager and supervisors concerning high dose rate, high radiation area, and very high radiation area controls and procedures, including procedural changes that had occurred since the last inspection, in order to assess whether any procedure modifications substantially reduced the effectiveness and level of worker protection.

This inspection constitutes one complete sample as defined in IP 71121.01-5.

The inspectors discussed with radiation protection supervisors the controls that were in place for special areas of the plant that had the potential to become very high radiation areas during certain plant operations. The inspectors assessed if plant operations required communication beforehand with the radiation protection group, so as to allow corresponding timely actions to properly post and control the radiation hazards.

This inspection constitutes one complete sample as defined in IP 71121.01-5.

The inspectors conducted plant walkdowns to assess the posting and locking of entrances to high dose rate high radiation areas and very high radiation areas.

This inspection constitutes one complete sample as defined in IP 71121.01-5.

b. Findings

No findings of significance were identified.

.4 Radiation Worker Performance

a. Inspection Scope

During job performance observations, the inspectors evaluated radiation worker performance with respect to stated radiation safety work requirements. The inspectors evaluated whether workers were aware of any significant radiological conditions in their workplace, of the RWP controls and limits in place, and of the level of radiological hazards present. The inspectors also observed worker performance to determine if workers accounted for these radiological hazards.

This inspection constitutes one complete sample as defined in IP 71121.01-5.

b. Findings

No findings of significance were identified.

.5 Radiation Protection Technician Proficiency

a. Inspection Scope

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

This inspection constitutes one complete sample as defined in IP 71121.01-5.

b. Findings

No findings of significance were identified.

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

.1 Job Site Inspections and ALARA Control

a. Inspection Scope

The inspectors observed the jobs described in Section 2OS1.2 that were being performed in radiation areas, airborne radioactivity areas, or high radiation areas to evaluate work activities that presented the greatest radiological risk to workers.

The inspectors reviewed the licensee's use of ALARA controls for those work activities. The licensee's use of engineering controls to achieve dose reductions was evaluated to verify that procedures and controls were consistent with the licensee's ALARA reviews, that sufficient shielding of radiation sources was provided, and that the dose expended to install and remove the shielding did not exceed the dose reduction benefits afforded by the shielding.

This sample was credited and documented in Inspection Report 05000266/2008003; 05000301/2008003; therefore, this supplemental information does not represent a sample.

b. Findings

No findings of significance were identified.

.2 Radiation Worker Performance

a. Inspection Scope

Radiation worker and radiation protection technician performance was observed during work activities being performed in radiation areas, airborne radioactivity areas, and high radiation areas that presented the greatest radiological risk to workers. The inspectors evaluated whether workers demonstrated the ALARA philosophy by being familiar with the scope of the work activity and tools to be used, by utilizing ALARA low dose waiting areas, and by complying with work activity controls. Also, radiation worker training and skill levels were reviewed to determine if they were sufficient relative to the radiological hazards and the work involved.

This inspection constitutes one required sample as defined in IP 71121.02-5.

b. Findings

No findings of significance were identified.

Cornerstone: Public Radiation Safety

2PS1 Radioactive Gaseous And Liquid Effluent Treatment And Monitoring Systems (71122.01)

.1 Inspection Planning

a. Inspection Scope

The inspectors reviewed the configuration of the licensee's gaseous and liquid effluent processing systems to confirm that radiological discharges were properly mitigated, monitored, and evaluated with respect to public exposure. The inspectors reviewed the performance requirements contained in General Design Criteria 60 and 64 of Appendix A to 10 CFR Part 50 and in the licensee's Radiological Effluent Technical Specifications (RETS) and Offsite Dose Calculation Manual (OCDM). The inspectors also reviewed any abnormal radioactive gaseous or liquid discharges and any conditions since the last inspection when effluent radiation monitors were out-of-service to verify that the required compensatory measures were implemented. Additionally, the inspectors reviewed the licensee's quality control program to verify that the radioactive effluent sampling and analysis requirements were satisfied and that discharges of radioactive materials were adequately quantified and evaluated.

The inspectors reviewed each of the radiological effluent controls program requirements to verify that the requirements were implemented as described in the licensee's RETS. For each system modification (since the last inspection), the inspectors reviewed changes to the liquid or gaseous radioactive waste system design, procedures, or operation, as described in the FSAR and plant procedures, as applicable. The inspectors reviewed any changes that were made to the liquid or gaseous waste systems to verify that the licensee adequately evaluated the changes and maintained effluent releases ALARA.

The inspectors reviewed changes to the ODCM made by the licensee since the last inspection to ensure consistency was maintained with respect to guidance in NUREG-1301, 1302, and 0133 and Regulatory Guides 1.109, 1.21, and 4.1. If differences were identified, the inspectors reviewed the licensee's technical basis or evaluations to verify that the changes were technically justified and documented.

For effluent monitoring instrumentation, the inspectors reviewed documentation to verify the adequacy of methods and monitoring of effluents, including any changes to effluent radiation monitor setpoints. The inspectors evaluated the calculation methodology and the basis for the changes to verify the adequacy of the licensee's justification.

The inspectors reviewed the licensee's program for identifying, assessing, and controlling contaminated spills and leaks. The inspectors also reviewed any new effluent discharge pathways (such as significant continuing leakage to ground water that continues to impact the environment if not remediated) to verify that the ODCM was updated to include the new pathway. The inspectors reviewed the radiological effluent release reports (Annual Monitoring Reports) for 2006 and 2007 in order to determine if anomalous or unexpected results were identified by the licensee, entered in the CAP, and adequately resolved.

The inspectors reviewed any significant changes in reported dose values among the 2005, 2006, and 2007 radiological effluent release reports and evaluated the factors which may have resulted in the change. If the change was not explained as being influenced by an operational issue (e.g., fuel integrity, extended outage, or major decontamination efforts), the inspectors independently assessed the licensee's offsite dose calculations to verify that the licensee's calculations were adequately performed and were consistent with regulatory requirements. No significant changes were identified.

The inspectors reviewed the licensee's correlation between the effluent release reports and the environmental monitoring results, as provided in Section IV.B.2 of Appendix I to 10 CFR Part 50. In addition, the inspectors reviewed the licensee audit results to determine whether the licensee met the requirements specified by the RETS/ODCM.

This inspection constitutes one complete sample as defined in IP 71122.01-5.

b. Findings

No findings of significance were identified.

.2 Onsite Inspection

a. Inspection Scope

The inspectors performed a walkdown of selected components of the gaseous and liquid discharge systems (e.g., demineralizers and filters (in use or in standby), tanks, and vessels) and reviewed current system configuration with respect to the description in the FSAR. The inspectors evaluated temporary waste processing activities, system modifications, and the equipment material condition. For equipment or areas that were not readily accessible, the inspectors reviewed the licensee's material condition surveillance records, as applicable.

During system walkdowns, the inspectors assessed the operability of selected point of discharge effluent radiation monitoring instruments and flow measurement devices. The effluent radiation monitor alarm set point values were reviewed to verify that the set points were consistent with RETS/ODCM requirements.

The inspectors discussed the licensee's sampling of liquid and gaseous radioactive waste (e.g., sampling of waste steams) and observed selected portions of the routine processing and discharge of radioactive effluents. The inspectors assessed whether the appropriate treatment equipment was used and whether the radioactive effluent was processed and discharged in accordance with RETS/ODCM requirements, including the projected doses to members of the public.

The inspectors interviewed staff concerning effluent discharges made with inoperable (declared out-of-service) effluent radiation monitors to determine if appropriate compensatory sampling and radiological analyses were conducted at the frequency specified in the RETS/ODCM. For compensatory sampling methods, the inspectors reviewed the licensee's practices to determine if representative samples were obtained and if the licensee routinely relied on the use of compensatory sampling in lieu of adequate system maintenance or calibration of effluent monitors.

The inspectors reviewed surveillance test results for non-safety-related ventilation and gaseous discharge systems for the containment purge and auxiliary building vent systems (high efficiency particulate air and charcoal filtration) to verify that the systems were operating within industry acceptance criteria. In addition, the inspectors assessed the methodology the licensee used to determine the stack/vent flow rates to verify that the flow rates were consistent with the RETS/ODCM.

The inspectors reviewed the licensee's program for identifying any normally non-radioactive systems that may have become radioactively contaminated to determine if evaluations (e.g., 10 CFR 50.59 evaluations) were performed per NRC Bulletin 80-10 ("Contamination of Nonradioactive Systems and Resulting Potential for Unmonitored, Uncontrolled Release to Environment"). The inspectors did not identify unidentified contaminated systems that may have been unmonitored discharge pathways to the environment.

The inspectors reviewed instrument maintenance and calibration records (i.e., both installed and counting room equipment) associated with effluent monitoring and reviewed quality control records for the radiation measurement instruments. The inspectors performed this review to identify any degraded equipment performance and to assess corrective actions, as applicable.

The inspectors reviewed the radionuclides that were included by the licensee in its effluent source term to determine if all applicable radionuclides were included (within detectability standards) in the licensee's evaluation of effluents. The inspectors reviewed waste stream analyses (10 CFR Part 61 analyses) to determine if hard-to-detect radionuclides were also included in the source term analysis.

The inspectors reviewed the meteorological dispersion and deposition factors and the hydrogeologic characteristics used in the licensee's ODCM and effluent dose calculations to verify that appropriate factors were used for public dose calculations. The inspectors also reviewed the most recent land-use census to verify that the licensee had included any new public dose receptors or pathways.

The inspectors reviewed the annual dose calculations to ensure that the licensee had properly demonstrated compliance with 10 CFR Part 50, Appendix I, and TS dose criteria.

The inspectors reviewed the licensee's implementation of the voluntary Nuclear Energy Institute (NEI)/Industry Ground Water Protection Initiative. The inspectors reviewed changes made to the Ground Water Protection Initiative, monitored results of the Ground Water Protection Initiative, identified leakage or spill events and entries made into 10 CFR 50.75(g) records, and evaluations of leaks or spills, including any remediation actions taken for effectiveness. The inspectors reviewed licensee records to identify any abnormal gaseous or liquid tank discharges (e.g., discharges resulting from misaligned valves, valve leak-by, etc.) to determine if the licensee had implemented the required actions. There were no abnormal effluent discharges since the last radioactive gaseous and liquid effluent monitoring inspection.

The inspectors reviewed onsite contamination events involving contamination of ground water and assessed whether the source of the leak or spill was identified and mitigated. Since the last inspection, there were no unmonitored spills, leaks, or unexpected radioactive liquid or gaseous discharges. The inspectors reviewed licensee records to verify that significant leaks and spills were properly documented in the licensee's CAP and/or in the decommissioning file, per 10 CFR 50.75(g). The inspectors reviewed the licensee's records to determine if sufficient radiological surveys were performed to evaluate the extent of the contamination and the radiological source term, and the inspectors reviewed survey/evaluation records to verify that the licensee had considered hard-to-detect radionuclides, as applicable.

The inspectors assessed if the licensee evaluated and analyzed any new or additional effluent discharge pathways as a result of a spill, leak, abnormal, or unexpected liquid discharge or gaseous discharges. The inspectors reviewed whether the licensee monitored groundwater discharges and determined if significant leaks and spills had been properly documented. The inspectors evaluated if the licensee's program included provision for required or voluntary offsite notifications to State and local officials and, if appropriate, to the NRC.

The inspectors assessed the licensee's program that evaluated discharges from onsite surface water bodies (ponds, retention basins, lakes) that contain or potentially contain radioactivity and the potential for leakage from these onsite surface water bodies into the groundwater. The inspectors assessed if the licensee accounted for discharges from these surface water bodies as part of its effluent release reports and reviewed routine groundwater monitoring results to assess whether the licensee monitored for unknown leakage. The inspectors reviewed the licensee's records to verify that the licensee sufficiently evaluated monitoring results, properly documented and reported the results, entered any abnormal results into its CAP, and implemented adequate corrective actions. Additionally, the inspectors reviewed the licensee's self-assessments, audits, and event reports that involved unanticipated offsite discharges of radioactive material.

The inspectors reviewed the results of the inter-laboratory comparison program to assess the quality of radioactive effluent sample analyses. The inspectors reviewed the licensee's effluent sampling records (sampling locations, sample analyses results, flow rates, and source term) for radioactive liquid and gaseous effluents to verify that the licensee's information satisfied the requirements of 10 CFR 20.1501.

This inspection constitutes one complete sample as defined in IP 71122.01-5.

b. Findings

Introduction: The inspectors identified a finding of very low safety significance and an associated NCV of TS 5.4.1 for the failure to establish procedures necessary to implement the effluent control program as provided in the ODCM to ensure that analytical equipment used to quantify effluents could achieve detection limits.

Description: The licensee used a multi-detector gamma spectroscopy system to analyze liquid and gaseous samples to quantify its effluent releases to the environment. Performance checks were performed daily on each detector prior to use to assess detector response compared to a mixed gamma-emitting radionuclide standard and, thereby, to determine measuring system capability and stability. Lower limits of detection (LLDs) were required to be met for various radionuclides and geometries (e.g., liquid and gas samples, charcoal cartridge or particulate filter samples) to ensure effluents were quantified to meet ALARA design objectives. The detection capabilities were based, in part, on the levels of background radiation present in the count laboratory, detector efficiency, and analysis parameters such as count time and volume.

The inspectors identified that, from 2007 through October 2008, approximately 20 percent of the daily performance checks of the gamma spectroscopy system failed initial testing, but subsequently successfully met quality control standards after retesting or following instrument repair. The instability was attributed by the licensee to detector age-related degradation, including repetitive instances of detector vacuum seal leakage. The inspectors identified that the licensee had not verified whether its spectroscopy system detectors could achieve the LLDs specified in the ODCM/Radiological Effluent Control Manual (RECM) during the periods of instrument instability. According to the licensee, a chemistry supervisor had periodically performed LLD determinations in the past, but those tests were discontinued unbeknownst to the licensee upon that person's employment termination in 2007. The licensee was unable to produce records to demonstrate when LLD verifications were last performed. The inspectors identified that the licensee's quality control program for its gamma spectroscopy equipment was not fully governed by procedure or other institutionalized processes including procedures to ensure LLD determinations were verified periodically or as dictated by instrument performance.

Sections 6.2 and 6.3 of the Point Beach RECM (incorporated into the ODCM by reference) required that radioactive liquid and gaseous waste be sampled and analyzed to meet specified LLDs in order to verify that concentrations of radioactive material in effluents satisfied the dose objectives of Appendix I to 10 CFR 50. Technical Specifications 5.4.1, 5.5.1, and 5.5.4 require that written procedures be established to implement the effluent control program as provided in the ODCM and RECM. However, no procedures were established to ensure gamma spectroscopy equipment effluent analyses capabilities were periodically demonstrated to meet LLD values specified in the ODCM/RECM.

Analysis: The inspectors determined that the licensee's failure to satisfy the requirements of TS 5.4.1 was a performance deficiency because the licensee failed to ensure adequate analytical instrument sensitivity to satisfy ODCM and RECM requirements.

The inspectors determined that the finding was more than minor in accordance with IMC 0612, Appendix B, "Issue Screening," dated December 4, 2008, because it impacted the program and process attribute of the Public Radiation Safety Cornerstone and affected the cornerstone objective of ensuring adequate protection of public health and safety from exposure to radioactive effluents. Specifically, given the instability in the licensee's gamma spectroscopy system since 2007, as evidenced by repetitive performance check failures, the ability of the equipment to achieve required LLDs could have been impacted or necessitated changes in analysis parameters (such as count times) resulting in non-conservative effluent quantification.

The finding was assessed using the Public Radiation Safety Significance Determination Process of IMC 0609, Appendix D, dated February 12, 2008, and was determined to be of very low safety significance because it was associated with the effluent release program but did not represent a substantial failure to implement that program or result in public dose which exceeded specified criterion. The finding was determined to involve a cross-cutting aspect in the resource component of the human performance area, because the licensee failed to develop procedures to fully implement its effluent program as provided in the ODCM/RECM. [H.2.(c)]

Enforcement: Technical Specification 5.4.1, 5.5.1, and 5.5.4 require written procedures be established, implemented, and maintained for the effluent control program as provided in the ODCM which incorporates the RECM. Sections 6.2 and 6.3 of the RECM (Revision 4) require that radioactive liquid and gaseous effluents be sampled and analyzed to meet specified LLDs. Contrary to these TSs, as of October 10, 2008, the licensee had not developed written procedures to implement its effluent control program to ensure effluent analyses met required LLDs. Since the failure to comply with TSs was of very low safety significance and the issue was entered into the licensee's CAP as AR 01137127, the violation is being treated as an NCV consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000266/2008005-05; 05000301/2008005-05).

As corrective actions, the licensee performed LLD determinations for its gamma spectroscopy equipment, demonstrated required LLDs could be achieved and developed procedure(s) to ensure LLDs were periodically determined as dictated by instrument performance consistent with industry standards.

.3 Identification and Resolution of Problems

a. Inspection Scope

The inspectors reviewed the licensee's self-assessments, audits, licensee event reports, and Special Reports, as applicable, related to the radioactive effluent treatment and monitoring program since the last inspection to determine if identified problems were entered into the CAP for resolution. The inspectors also assessed whether the licensee's self-assessment program was capable of identifying repetitive deficiencies or significant individual deficiencies in problem identification and resolution.

The inspectors reviewed corrective action reports from the radioactive effluent treatment and monitoring program since the previous inspection, interviewed staff, and reviewed documents to determine if the following activities were conducted in an effective and timely manner commensurate with their importance to safety and risk:

- 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;
- identification and implementation of effective corrective actions;
- resolution of NCVs tracked in the corrective action system;
- implementation/consideration of risk-significant operational experience feedback; and
- ensuring problems were identified, characterized, prioritized, entered into a corrective action, and resolved.

This inspection constitutes one complete sample as defined in IP 71122.01-5.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification (71151)

.1 Mitigating Systems Performance Index (MSPI) - Emergency AC Power System

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI emergency AC (alternating current) power system PI for Unit 1 and Unit 2 for the second quarter 2007 through the second quarter of 2008. To determine the accuracy of this PI data, definitions and guidance contained in NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5, were used. The inspectors reviewed the licensee's operator narrative logs, MSPI derivation reports, issue reports, event reports, and NRC integrated inspection reports for April 2007 through June 2008 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. Documents reviewed are listed in the Attachment.

This inspection constituted two MSPI emergency AC power system samples as defined in IP 71151-05.

b. Findings

No findings of significance were identified.

.2 Mitigating Systems Performance Index - High Pressure Injection Systems

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI high pressure injection systems PI for Unit 1 and Unit 2 for the second quarter 2007 through the second quarter 2008. To determine the accuracy of this PI data, definitions and guidance contained in NEI 99-02, Revision 5, were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, MSPI derivation reports, event reports, and NRC integrated inspection reports for April 2007 through June 2008 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. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two MSPI high pressure injection system samples as defined in IP 71151-05.

b. Findings

No findings of significance were identified.

.3 Mitigating Systems Performance Index - Heat Removal System

a. Inspection Scope

The inspectors sampled licensee submittals for the MSPI heat removal system PI for Unit 1 and Unit 2 for the second quarter 2007 through the second quarter of 2008. To determine the accuracy of this PI data, definitions and guidance contained in NEI 99-02, Revision 5, were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, event reports, MSPI derivation reports, and NRC integrated inspection reports for April 2007 through June 2008 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. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two MSPI heat removal system samples as defined in IP 71151-05.

b. Findings

No findings of significance were identified.

.4 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 Unit 1 and Unit 2 for the second quarter 2007 through the second quarter 2008. To determine the accuracy of the PI data reported, definitions and guidance contained in NEI 99-02, Revision 5, were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, MSPI derivation reports, event reports, and NRC integrated inspection reports for April 2007 through June 2008 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. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two MSPI residual heat removal system samples as defined in IP 71151-05.

b. Findings

No findings of significance were identified.

.5 Radiological Effluent Technical Specification/Offsite Dose Calculation Manual (RETS/ODCM) Radiological Effluent Occurrences

a. Inspection Scope

The inspectors sampled licensee submittals for the RETS/ODCM Radiological Effluent Occurrences PI for November 2007 through September 2008. The inspectors used definitions and guidance contained in NEI 99-02, Revision 5, to determine the accuracy of the PI data. The inspectors reviewed the licensee's AR database and selected individual ARs generated since this indicator was last reviewed to identify any potential occurrences such as unmonitored, uncontrolled, or improperly calculated effluent releases that may have impacted offsite dose. The inspectors reviewed gaseous effluent summary data and the results of associated offsite dose calculations for selected dates between December 2007 and September 2008 to determine if indicator results were accurately reported. The inspectors also reviewed the licensee's methods for quantifying gaseous and liquid effluents and determining effluent dose. Documents reviewed are listed in the Attachment to this report.

This inspection constitutes one RETS/ODCM radiological effluent occurrence sample defined in IP 71151-05.

b. Findings

No findings of significance were identified.

4OA2 Problem Identification and Resolution (71152)

.1 Routine Review of items Entered Into the Corrective Action Program (CAP)

a. Inspection Scope

As part of the various baseline inspection procedures discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that they were being entered into the licensee's CAP at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. Attributes reviewed included: the complete and accurate identification of the problem; timeliness was commensurate with the safety significance; evaluation and disposition of performance issues, generic implications, common causes, contributing factors, root causes, extent-of-condition reviews and previous occurrences reviews were proper and adequate; and the classification, prioritization, focus, and timeliness of corrective actions were commensurate with safety and sufficient to prevent recurrence of the issue. Minor issues entered into the licensee's CAP as a result of the inspectors' observations are listed in the Attachment to this report.

These routine reviews for the identification and resolution of problems did not constitute any additional inspection samples. Instead, by procedure, they were considered an integral part of the inspections performed during the quarter and documented in Section 1 of this report.

b. Findings

No findings of significance were identified.

.2 Daily CAP Reviews

a. Inspection Scope

To assist with the identification of repetitive equipment failures and specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee's CAP. This review was accomplished through inspection of the station's daily condition report packages.

These daily reviews were performed by procedure as part of the inspectors' daily plant status monitoring activities and, as such, did not constitute any separate inspection samples.

b. Findings

No findings of significance were identified.

.3 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a review of the licensee's CAP 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 4OA2.2 above, licensee trending efforts, and licensee human performance results. The inspectors' review nominally considered the six-month period of July 1, 2008, through December 31, 2008, although some examples expanded beyond those dates where the scope of the trend warranted.

The review also included issues documented outside the normal CAP 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 CAP trending reports. Corrective actions associated with a sample of the issues identified in the licensee's trending reports were reviewed for adequacy.

The inspectors did note an apparent negative trend in the characterization of ARs characterized as either a condition adverse to quality or non-condition adverse to quality since the institution of the new fleet procedure in the second quarter of 2008. The licensee initiated AR 01141302 to assess the inspectors' observations.

This review constituted one semi-annual trend inspection sample as defined in IP 71152-05.

b. Findings

No findings of significance were identified.

.4 Annual Sample: Review of Operator Workarounds (OWAs)

a. Inspection Scope

The inspectors evaluated the licensee's implementation of their process used to identify, document, track, and resolve operational challenges. Inspection activities included, but were not limited to, a review of the cumulative effects of the OWAs on system availability and the potential for improper operation of the system, for potential impacts on multiple systems, and on the ability of operators to respond to plant transients or accidents.

The inspectors performed a review of the cumulative effects of OWAs. The documents listed in the attached were reviewed to accomplish the objectives of the inspection procedure. The inspectors reviewed both current and historical operational challenge records to determine whether the licensee was identifying operator challenges at an appropriate threshold, had entered them into the CAP and proposed or implemented appropriate and timely corrective actions that addressed each issue. Reviews were conducted to determine if any operator challenge could increase the possibility of an initiating event, if the challenge was contrary to training, required a change from long-standing operational practices, or created the potential for inappropriate compensatory actions. Additionally, all temporary modifications were reviewed to identify any potential effect on the functionality of mitigating systems, impaired access to equipment, or required equipment uses for which the equipment was not designed. Daily plant and equipment status logs, degraded instrument logs, and operator aids or tools being used to compensate for material deficiencies were also assessed to identify any potential sources of unidentified operator workarounds.

This review constituted one operator workaround annual inspection sample as defined in IP 71152-05.

b. Findings and Observations

The inspectors reviewed procedure NP 2.1.4, "Operator Burdens," Revision 9, which was the licensee guidance document for the identification, tracking, and resolution of operator burdens, and the assessment of any adverse effects on plant operations created by operator burdens. In accordance with NP 2.1.4, operator workarounds were required to be graded to assist in the prioritization of issues as well as to have the aggregate Probabilistic Risk Analysis (PRA) impact of the workarounds calculated. The inspectors identified that the numeric values listed as the "contribution of system failures to core damage frequency" in the procedure were not reflective of the current PRA model values. The PRA model was revised substantially in March 2008, but the new risk numbers were not incorporated into NP 2.1.4.

Once informed of the issue, the licensee entered the issue into its CAP. The licensee performed a reassessment of all open operator workarounds and found that neither the prioritization grades nor the aggregate impact factors changed appreciably when recalculated with the current PRA inputs. Therefore, the inspectors determined that this issue was minor in nature. Additionally, the licensee has since revised NP 2.1.4 to refer directly to the PRA model of record to obtain the PRA inputs, rather than including an excerpt from the PRA model in the NP 2.1.4 procedure as previously done.

No findings of significance were identified.

.5 Selected Issue Follow-up Inspection: Review of Independent Self-Assessment of Engineering Effectiveness

Introduction

The inspectors selected several corrective and follow-up actions resulting from the 2007 Independent Assessment (Assessment Report) for a more in-depth review in accordance with inspection procedure requirements.

This review constituted one inspection sample.

a. Effectiveness of Problem Identification

(1) Inspection Scope

The inspectors reviewed the Assessment Report and resulting ARs to verify that the licensee's identification of issues was 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 ARs and condition evaluations associated with issues identified in the Assessment Report. 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. While evaluation of the identified issues was considered generally thorough, staffing remains an issue within certain engineering departments. Also, corrective action backlog reduction, principally in system engineering, remains a challenge for the licensee.

c. Effectiveness of Corrective Actions

(1) Inspection Scope

The inspectors reviewed condition reports, licensee PIs, applicable procedures, and effectiveness reviews to determine if the licensee's corrective actions resulting from the 2007 Independent Assessment were effective. 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. Engineering staffing and corrective action backlog reduction remain a challenge for the licensee; however, the licensee has continued to address these issues since the 2007 Independent Assessment and has made some progress.

4OA3 Follow-up of Events and Notices of Enforcement Discretion (71153)

.1 (Closed) Licensee Event Report LER 05000266/2007-008-00; 05000301/2007-008-00: Non-Conservative Low Temperature Overpressure Protection (LTOP) System Basis

a. Inspection Scope

On October 25, 2007, the LTOP system actuation setpoints for Unit 1 and Unit 2 were found to be non-conservative and both systems were declared inoperable. The licensee subsequently changed the setpoints and restored LTOP operability on October 26. The inspectors reviewed the circumstances surrounding this event and the licensee's evaluation of the event, the design basis of the LTOP system, and corrective actions taken. Documents reviewed as part of this inspection are listed in the Attachment.

b. Findings

Non-Conservative LTOP Setpoints

Introduction: A finding of very low safety significance and associated NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," was self-revealed when it was discovered that the setpoints for the LTOP systems for Unit 1 and Unit 2 were non-conservative. Specifically, the licensee calculation, used for operation of the plants from 2000 through 2007, specified an LTOP setpoint of 500 pounds per square inch-gauge (psig) as opposed to the correct setpoint of 420 psig.

Description: Title 10 CFR Part 50, Appendix G, "Fracture Toughness Requirements," contains the requirements for pressure-temperature limits and minimum temperature of the reactor vessel. Table 1 of Appendix G contains the minimum temperature requirements for the condition and pressure of the reactor vessel. This table defines the closure flange region as the controlling material due to high stresses from the bolting preload. It also defines the maximum allowable pressure as <20 percent of the system's pre-service hydrostatic test pressure, or 621 psig at Point Beach. This pressure is then used to calculate the LTOP setpoint.

Calculation 2000-001, "RCS Pressure-Temperature Limits and LTOP Setpoints Applicable Through 32.2 EFPY [Effective Full Power Years] – Unit 1 and 34.0 EFPY - Unit 2," approved on March 5, 2000, provided the design basis LTOP actuation setpoints for Point Beach Unit 1 and Unit 2. This calculation used beltline region weld properties to determine a maximum allowable pressure of 712.5 psig. Using this pressure, the LTOP setpoint was established at 500 psig.

On February 2, 2004, the licensee received a Westinghouse LTOP system setpoint report. The Westinghouse report concluded the maximum allowable setpoints to prevent RCS pressure from exceeding the applicable Appendix G limits over the full range of temperatures when the LTOP system was enabled, without any restrictions on the number of reactor coolant pumps (RCPs) running, was 390 psig. This calculation used a maximum allowable pressure of 621 psig (not 712.5 psig used by the licensee calculation). This discrepancy was not identified by engineering personnel and no action was taken on the lower setpoint value at the time.

On February 1, 2007, Westinghouse transmitted another LTOP system setpoint report. This report concluded the LTOP setpoints were 384 psig without operating restrictions on RCPs, or 420 psig with specific operating restrictions on the RCPs and charging pumps. This report also used the reactor vessel flange material as the limiting material and 621 psig as the maximum pressure allowed. The licensee again did not identify the discrepancy of the maximum allowable pressure used, nor was the issue of the lower setpoint value entered into the CAP for evaluation at the time.

On October 19, 2007, it was self-revealed that the LTOP setpoints were non-conservative based on a number of factors, such as safety injection pump flow rate changes, instrument delay times, and instrument uncertainties (AR 01114739). These factors were derived from a Westinghouse calculation, WCAP 16669-NP, received by the licensee in February 2007 and was not identified through the licensee's normal processes. An event notification was submitted to the NRC on October 25, 2007, when it was determined the setpoints were non-conservative for both units, and the LTOP systems were declared inoperable. Operability of the LTOP systems for both units was restored on October 26, 2007, with setpoints set at 420 psig and the operating procedures changed to incorporate the specific operational restrictions of the RCPs and charging pumps during low temperature conditions.

On November 16, 2007, the licensee identified an additional discrepancy with calculation 2000-001 (AR 01116679). This discrepancy involved the use of the maximum allowable pressure of 712.5 psig instead of the maximum allowable pressure allowed by the requirements of Appendix G, 621 psig. Although there was some error associated with instrument uncertainties and pump flow rates, this discrepancy was determined to account for the majority of the non-conservatism between the 500 psig and 420 psig setpoint values.

The inspectors determined that the licensee had two previous opportunities to identify the design error in the LTOP calculation (on February 2, 2004, and February 1, 2007); that the error was not found through a systematic licensee process; and that the error was significant and visible to the organization. Therefore, this finding was determined to be self-revealed.

Analysis: The inspectors determined that the use of an LTOP setpoint of 500 psig for approximately 8 years, which, when found to be non-conservative, led to the LTOP systems for Unit 1 and Unit 2 being declared inoperable, was a performance deficiency.

The finding was determined to be more than minor in accordance with IMC 0612, Appendix B, "Issue Screening," dated December 4, 2008, because the finding was associated with the human performance attribute of the Barrier Integrity Cornerstone and affected the cornerstone objective of providing reasonable assurance that physical design barriers, such as the RCS, protect the public from radionuclide releases caused by accidents or events. Specifically, the higher LTOP setpoint provided reasonable doubt that the integrity of the RCS pressure boundary would be maintained during low temperature conditions.

The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Phase 1 - Initial Screening and Characterization of Findings," Table 4a for the Barrier Integrity Cornerstone, dated January 10, 2008. The inspectors determined that the finding was of very low safety significance because all of the questions in the containment barrier column of Table 4a were answered NO, and because the actual setpoint of the power operated relief valves was always 415 psig, below the revised LTOP setpoint. Further, while in low temperature conditions during the period in question, the RCPs and charging pumps were never operated in a configuration that would have invalidated the 420 psig limit.

The inspectors also determined that this finding has a cross-cutting aspect in the area of problem identification and resolution, CAP component, because personnel did not use a low threshold for identifying issues. Specifically, licensee personnel failed in February 2007 to enter the issue of the existence of a more conservative setpoint into the CAP, where an evaluation should have identified the error in the calculation. [P.1(a)]

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

Contrary to the above, from March 2000 through October 2007, the licensee failed to translate applicable regulatory requirements into calculation 2000-001. Specifically, the calculation did not use the most limiting reactor vessel weld properties and maximum allowable pressure as required by 10 CFR Part 50, Appendix G, resulting in a non-conservative setpoint of the LTOP systems for Unit 1 and Unit 2. Because this violation was of very low safety significance and it was entered into the licensee's CAP as AR 01114739 and AR 01116679, this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 05000266/2008005-06; 05000301/2008005-06).

As an immediate corrective action, the licensee revised the LTOP setpoint from 500 psig to 420 psig and made changes to the operating procedures to incorporate the specific operational restrictions of the RCPs and charging pumps during low temperature conditions.

This LER is considered closed.

4OA5 Other Activities

.1 (Closed) Unresolved Item (URI) 05000266/2007003-03; 050000301/2007003-03: Failure to Submit RCS Pressure and Temperature Limits Report (PTLR)

a. Inspection Scope

The inspectors interviewed personnel and reviewed licensee records and procedures in an inspection of URI 2007003-03 concerning the licensee's potential use of an unapproved methodology to calculate the Unit 1 PTLR upon its expiration in February 2004.

b. Findings

Introduction: The inspectors identified a finding of very low safety significance and associated Severity Level IV NCV of Point Beach TS 5.6.5(c), "Reactor Coolant System

(RCS) Pressure and Temperature Limits Report (PTLR)," for the failure to submit a revised Unit 1 PTLR for a new fluence period. Specifically, TS 5.6.5(c) required the PTLR be provided to the NRC for each reactor fluence period. Based on the references in TS 5.6.5(b), the fluence period for the PTLR, Revision 1, could not be extended past February 2004; however, the revised PTLR, Revision 2, was not submitted until November 15, 2007.

Description: In May 2007, while reviewing Point Beach license amendment request 251 for TS 5.6.5(c), the NRC questioned the licensee on whether Unit 1 had exceeded the applicability limit for the PTLR as specified in the Safety Evaluation Report (SER) dated July 23, 2001, and the validity of the PTLR after this date. The following summarizes the sequence of events associated with this violation:

- July 23, 2001: The NRC SER accepted Point Beach TS Change Request 219, which relocated the PTLR curves to the Technical Requirement Manual (TRM). The safety evaluation included limits that the PTLR curve for Unit 1 was only valid until 25.59 Effective Full Power Years (EFPY), or October 1, 2003.

- November 7, 2003: The licensee submitted a letter to the NRC, summarizing a phone call held with the NRC stating the applicability date for the Unit 1 PTLR as February 2004 based on actual plant operation history since the safety evaluation. The letter also stated the licensee still planned on submitting new curves that met TSs 5.6.5(b) and (c) prior to Unit 1 reaching 25.59 EFPY.

- December 20, 2003: The PTLR was revised by the licensee to change the basis of the PTLR curve applicability limits from EFPY to accumulated fluence values contained in tables in the PTLR. This change was screened under the 50.59 process but was not reviewed by the plant review committee or submitted to the NRC. This change may have led the licensee to make the incorrect assumption that they could change fluence periods, notably the 25.59 EFPY period in the SER, without NRC approval.

- January 29, 2004: An entry in the corrective action system stated that the PTLR curve applicability date for Unit 1 was valid until August 2004 based on fluence limits but no further details were provided. It appeared to the inspectors that the licensee's bases were fluence curves from Westinghouse report WCAP-15976, which used NRC-approved methodology.

- February 10, 2004: The EFPY applicability date for the Unit 1 PTLR curve was reached with no additional submittals sent to the NRC. At that time, the PTLR contained in the TRM was no longer valid and thus began the period in which Point Beach was in violation of TS 5.6.5(c).

- August 27, 2004: A corrective action document was closed-out to the statement that the PTLR was valid until October 2005 based on fluence curves from Westinghouse report LTR-REA-04-64, which used an NRC-approved methodology.

- June 1, 2005: Another corrective action document concluded the PTLR was valid until spring 2007. The licensee subsequently concluded in its investigation of the PTLR issue that the engineer used the same Westinghouse report (LTR-REA-04-64), although this time the fluence period applicability was derived from the unapproved FERRET code tables in the report.

- January 2006: NRC approved the generic use by nuclear utilities of the FERRET code to calculate PTLR curves.

- February 2006: Point Beach personnel determined the fluence data from the Westinghouse report were incorrectly used and that the calculated fluence limit for the limiting weld on Unit 1 was exceeded. Unit 1 operability was justified using the recently approved generic version of the FERRET code. However, the licensee did not identify that they had violated TSs 5.6.5(b) and 5.6.5(c).

- December 14, 2006: Point Beach submitted a license amendment request to allow the use of FERRET code.

- May 16, 2007: The licensee recognized, through questioning by the NRC, that the TS requirements had not been met. The licensee then entered the issue into the CAP. The subsequent licensee root cause evaluation concluded that the unapproved FERRET code was used, which rendered previous calculations invalid.

- November 15, 2007: Revision 2 of the PTLR was submitted to the NRC, and upon acceptance, ending the violation of TS 5.6.5(c).

Technical Specification 5.6.5(b) states, " The analytical methods used to determine the RCS pressure and temperature limits shall be those previously reviewed and approved by the NRC, specifically those described in the NRC letters dated October 6, 2000, and July 23, 2001." The July 23, 2001, reference is the NRC SER, which included the stipulation that the PTLR curve for Unit 1 would only remain valid until Unit 1 reached 25.59 EFPY.

TS section 5.6.5(c) also states, "The PTLR report shall be provided to the NRC upon issuance for each reactor vessel fluence period and for any revision or supplement thereto." On November 7, 2003, the licensee sent a letter to the NRC stating the new PTLR curves would be submitted by February 2004 based on reaching the 25.59 EFPY. This was defined as the fluence period for revision 1 of the Unit 1 PTLR. Since the engineering staff incorrectly extended the fluence period of the existing curves, the PTLR was not submitted to the NRC for the new fluence period, resulting in the violation to the TS requirement.

Analysis: The inspectors determined that the failure to submit a revised PTLR for the new fluence period was a performance deficiency. The finding was determined to be more than minor in accordance with IMC 0612, Appendix B, "Issue Screening," dated December 4, 2008, because the finding is associated with the design control attribute of the Barrier Integrity Cornerstone and affected the cornerstone objective to provide reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. Specifically, the PTLR, which specifies plant operating conditions to ensure the integrity of the reactor vessel, was not valid after February 2004. This finding is not suitable for SDP evaluation, but has been reviewed by NRC management and is determined to be a finding of very low safety significance.

Subsequent calculations using an NRC-approved methodology determined that the Unit 1 reactor vessel was not outside of the safety limits and was fully capable of performing its required function.

The inspectors did not identify a cross-cutting aspect associated with this finding because it was not determined to be indicative of current licensee performance.

Enforcement: Point Beach TS 5.6.5(c) states, "The PTLR report shall be provided to the NRC upon issuance for each reactor vessel fluence period and for any revision or supplement thereto." Contrary to this, on February 10, 2004, the licensee failed to submit a revised Unit 1 PTLR for the new fluence period. Specifically, the licensee inappropriately extended the fluence period of the existing PTLR multiple times, failing to develop and submit a revised PTLR for the new fluence period that started in February 2004. This violation was determined to be of very low safety significance; therefore, this violation of TS was classified as a Severity Level IV violation. Because this violation was of very low safety significance, was not repetitive or willful, and was entered into the licensee's CAP as AR 01092944, this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 05000266/2008005-07).

Licensee corrective actions included the submittal of a revised PTLR (revision 2) on November 15, 2007. This URI is considered closed.

.2 Implementation of Temporary Instruction (TI) 2515/176, "Emergency Diesel Generator TS Surveillance Requirements Regarding Endurance and Margin Testing"

a. Inspection Scope

The objective of TI 2515/176 was to gather information to assess the adequacy of nuclear power plant emergency diesel generator endurance and margin testing as prescribed in plant-specific TSs. The inspectors reviewed the licensee's TSs, procedures, and calculations and interviewed licensee personnel to complete the TI. The information gathered for this TI was forwarded to the Office of Nuclear Reactor Regulation for further review and evaluation on December 17, 2008. This TI is complete at Point Beach; however, this TI 2515/176 will not expire until August 31, 2009. Additional information may be required after review by the Office of Nuclear Reactor Regulation.

b. Findings

No findings of significance were identified.

4OA6 Management Meetings

.1 Exit Meeting Summary

On January 7, 2009, the inspectors presented the inspection results to Mr. L. Meyer 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 Meetings

- Occupational Radiation Safety ALARA and Public Radiation Safety effluent control program inspection with Mr. L. Meyer and others on October 10, 2008, and with Mr. D. Frey and Mr. D. Farrell during a teleconference on November 7, 2008.
- Baseline Inservice Inspection procedure 71111.08 with Mr. L. Meyer on October 24, 2008.
- A telephone exit for TI 2515/176 was conducted with Mr. J. Costedio, Licensing Manager, and other Licensee staff on December 1, 2008.
- The annual review of Emergency Action Level and Emergency Plan changes with the licensee's Emergency Preparedness Manager, Mr. R. Freeman, via telephone on December 29, 2008.

The inspectors confirmed that none of the potential report input discussed was considered proprietary.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

R. Amundson, General Supervisor Operations Training
R. Bardo, ISI Program Engineer
J. Bjorseth, Plant Manager
D. Farrell, Radiation Protection Manager
F. Flentje, Regulatory Affairs Supervisor
R. Freeman, Emergency Preparedness Manager
D. Frey, Chemistry Manager
S. Forsha, Reactor Vessel Program Engineer
D. Frey, Chemistry Manager
J. Hofstra, Boric Acid Program Engineer
B. Jensen, NDE Level III
C. Jilek, Site Maintenance Rule Coordinator
K. Johansen, Environmental Specialist
J. Keltner, SG Program Engineer
K. Locke, Regulatory Affairs Specialist
L. Meyer, Site Vice-President

Nuclear Regulatory Commission

J. Cushing, Point Beach Project Manager, Office of Nuclear Reactor Regulations
M. Kunowski, Chief, Division of Reactor Projects, Branch 5

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened and Closed

05000266/2008005-01	NCV	Failure to Perform Evaluations on Boric Acid Leaks (Section 1R08.3)
05000266/2008005-02	NCV	Draindown of RCS with Inaccurate Pressurizer Level Indication Due to Inadequate Procedure (Section 1R20.1)
05000266/2008005-03	NCV	Failure to Appropriately Install Unit 1 Debris Interceptors in Accordance with Installation Work Order (Section 1R20.2)
05000266/2008005-04; 05000301/2008005-04	NCV	Inadequate Inspection Procedure for Containment Polar Crane Structures (Section 1R20.3)
05000266/2008005-05; 05000301/2008005-05	NCV	Failure to Establish Procedures to Implement the Effluent Control Program as Provided in the ODCM (Section 2PS1.2)
05000266/2008005-06; 05000301/2008005-06	NCV	Non-Conservative Low Temperature Overpressure Protection Setpoints (Section 4OA3.1)
05000266/2008005-07	NCV	Violation of TS 5.6.5(c) – PTLR Not Submitted (Section 4OA5.1)

Closed

05000266/2007-008; 05000301/2007-008	LER	Non-Conservative Low Temperature Overpressure Protection System Basis (Section 4OA3.1)
05000266/2007003-03; 05000301/2007003-03	URI	Failure to Submit Reactor Coolant System Pressure and Temperature Limits Report (Section 4OA5.1)

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 inspectors 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.

1R04 Equipment Alignment

- CL 5C; Spent Fuel Pool Cooling and Refueling Water Circulating Pump Normal Operation Valve Lineup; Revision 12
- CL 10B; Service Water Safeguards Lineup; Revision 62
- DBD-13; Spent Fuel Pool Cooling and Filtration Design Basis Document; Revision 5
- OI 62B; Turbine Driven Auxiliary Feedwater System (P-29); Revision 16
- IT-09A; Cold Start of Turbine Driven Auxiliary Feed Pump and Valve Test (Quarterly) Unit 2; Revision 47
- CL 16A; Gas Turbine G05; Revision 19
- WO Search for all Open WOs Relating to G05 Gas Turbine

1R05 Fire Protection

- Fire Hazards Analysis Report; Revision 6
- NP 1.9.9; Transient Combustible Control
- NP 1.9.13; Ignition Control Procedure; Revision 13

1R07 Annual Heat Sink Performance

- Bio/Silt Fouling Inspection Form for WO 347346; HX-15A-1 through 8; performed October 16, 2008
- Bio/Silt Fouling Inspection Form for WO 347345; HX-15B-1 through 8; performed October 14-17, 2008
- Bio/Silt Fouling Inspection Form for WO 347347; HX-15C-1 through 8; performed October 22, 2008
- Bio/Silt Fouling Inspection Form for WO 347348; HX-15D-1 through 8; performed October 24, 2008
- AR 01138413; 1HX-015D1 Has 29 Tubes Blocked or Partially Blocked
- AR 01137899; U1 Containment Fan Cooler HX's Are Clean
- CE 1058442; CFC Silting Issues; November 10, 2006
- HX-01; Heat Exchanger Condition Assessment Program; Revision 6

1R08 Inservice Inspection Activities (ISI)

- AR 01137814; Boric Acid Leak Program Attribute Not Selected on WR
- AR 01137817; NRC RFI regarding CA/WO Closure with Completion of Structural Evaluation
- AR 01138318; NRC Field Observations During ISI Inspection
- AR 01138361; NRC Issues with the Screening of AR's
- AR 01114661; 1SC-967C Leaks from Stem
- AR 01115310; Boric Acid on Stainless Steel Pipe Below 2SI-855A
- AR 01116166; 1CV-262A Leaking Boric Acid
- AR 01118739; Boric Acid on 2RH-D-9 and 2SI-843A

- AR 01119055; Significant Boric Acid Found on 1SC-959
- AR 01120405; Boric Acid on 1PT-173
- AR 01120646; Boric Acid Build Up on Hose Connection
- AR 01123880; Boric Acid Leakage Discovered During U-2 Containment Entry
- AR 01132026; Active Boric Acid Leak 1GS-14
- AR 01132185; 1P-2C Charging Pump has Boric Acid Build Up
- AR 01136480; 1FT-128 High Side Vent Leakage
- AR 01138251; Unresolved ET Acquisition Issues
- AR 01120747; Apparent Lack of Support for Boric Acid Program
- AR 01116425; EPRI/MRP Issues Letters MRP 2007-038 and 039
- AR 01127274; Issue Concerning “Pre” RCS Walkdown by Engineering Programs
- AR 01110614; Requirements in NP 3.1.1 for Penetrant Exams Questioned
- AR 01115037; Schedule of 10-Year RPV Questioned by FPL
- NDE-172; PDI Generic Procedure for the Ultrasonic Examination of Ferritic Piping Welds; Revision 10
- NDE-451; Visible Dye Penetrant Examination Temperature Applications 45 – 125 deg; Revision 25
- NDE-750; Visual Examination (VT-1) of Nuclear Power Plant Components; Revision 2
- NDE-754; Visual Examination (VT-3) of Nuclear Power Plant Components; Revision 16
- NDE-760; VT-1 and VT-3 Visual Examination of IWE Boundary Components (Metal Containment and Metallic Liners of Concrete Containment)
- IDR 2007-018; AF-03-AFW-1002-2 Pipe to Valve Weld; dated April 17, 2007
- IDR 2007-021; SI-1051R-1-H3 Component Spring Support; dated April 30, 2007
- IDR 2007-024; SI-301R-1-H8 Component Spring Support; dated April 30, 2007
- BAE 07-0136; 1RO-900A Containment Spray Pump Flow Orifice; dated April 8, 2007
- BAE 07-0144; 1SI-D-31 Containment Spray Test Line Drain; dated April 11, 2007
- BAE 07-0198; 1CV-1299A HX-4 Inlet; dated May 4, 2007
- BAE 07-0194; 1CV-371B; Letdown Line Containment Manual Isolation; dated May 4, 2007
- BAE 07-0223; 1SC-966C RC Hot Leg Sample; dated May 4, 2007
- BAE 08-0059; 1SI-860B P-14A Containment Spray Pump Discharge Isolation; dated March 26, 2008
- BAE 08-0041; 1SI-870B P-14B Containment Spray Pump Suction from RWST; dated March 6, 2008
- BAE 08-0120; 1CV-280A 1P-2A Pump Casing Drain; dated March 30, 2008
- BAE 08-0144; 1CV-384A CV-142 Charging Line Flow Inlet Isolation; dated March 31, 2008
- BAE 08-0330; 1GS-14 Hx 132A LGS PreHeater Vent; dated August 28, 2008
- WE letter from T. M .Siehr to J. B. Brander; Spring Hanger Load Settings Tolerances; dated June 28, 1994.
- Boric Acid Leakage and Corrosion Monitoring Program; Revision 4
- Boric Acid Leakage and Corrosion Monitoring Program; Appendix B; Revision 2
- Boric Acid Leakage and Corrosion Monitoring Program; Appendix C; Revision 5
- Boric Acid Leakage and Corrosion Monitoring Program, NP 7.4.14; Revision 5
- VT-1 Exam Data Sheet 2008VT-021; CVC-02-PSI-1002-35-FB; dated October 9, 2008
- VT-1 Exam Data Sheet 2008VT-022; Valve 1SI-867B-BLT; dated October 9, 2008
- VT-3 Exam Data Sheet 2008VT-023; SG B Support; dated October 9, 2008
- VT-3 Exam Data Sheet 2008VT-026; RC-2501R-1-RCS; dated October 14, 2008
- VT-3 Exam Data Sheet 2008VT-027; RHR-B-LEG-1 thru 4; dated October 24, 2008
- UT Exam Data Sheet 2008UT-071; RHR-B-1 Shell to Head Weld; dated October 23, 2008
- UT Exam Data Sheet 2008VT-072; RHR-B-2 Shell to Flange Weld; dated October 23, 2008.
- Letter from FPL Energy to NRC 2008-0066; Supplement to License Amendment Request 257, Interim Alternate Repair Criteria for Steam Generator Tube Repair; dated July 18, 2008

- NP 7.7.16; Steam Generator Program; Revision 10
- NP 7.7.17; Requirements for Steam Generator Primary Side Activities; Revision 8
- SG-CDME-08-32; Steam Generator Degradation Assessment for Point Beach Unit 1, U1R31; Revision 0
- MRS-TRC-1918; Point Beach Unit Appendix H Techniques for Fall 2008 S/G Inspection; dated September 18, 2008
- ETTS 96004.1; Eddy Current Examination Technique Specification Sheet for Bobbin Coil Examination at Supports and Anti-vibration Bars; Revision 11
- ETTS 96511.2; Eddy Current Examination Technique Specification Sheet for +Point Examination of Low Row U-Bend Tubes; Revision 10
- ETTS 20510.1; Eddy Current Examination Technique Specification Sheet for +Point Detection of Circumferential Primary Water Stress Corrosion Cracking; Revision 11
- ETTS 21409.1; Eddy Current Examination Technique Specification Sheet for +Point Detection of Axial Outer Diameter Corrosion Cracking at Support Structures; Revision 5
- ETTS 21410.1; Eddy Current Examination Technique Specification Sheet for +Point Detection of Circumferential Outer Diameter Stress Corrosion Cracking at Expansions Transitions; Revision 6
- WO 191907-01; Disassemble Pipe Plug, Clean, and Weld New Plug on Line SI 0301-R; dated April 12, 2007
- WO Work Plan 335667 Task 01; Replace Valve CV-0303B 1F39B RCP Seal Injection Filter Inlet; dated October 6, 2008
- Repair/Replacement Form 2007-0031; dated April 12, 2007
- Weld Procedure Specification FP-PE-B312-P8P8-GTSM-037; Revision 3
- Welder Performance Qualification, T.W. Dums; Revision 2
- Welder Procedure Qualification Record PrQR-W-12; dated June 4, 1975
- Welder Procedure Qualification Record W-66; dated October 12, 1989
- Welder Procedure Qualification Record SM-8-8; dated September 18, 1973
- Welder Procedure Qualification Record 91-P8P8F6F5-2; dated November 21, 1991

1R11 Licensed Operator Requalification Program

- FP-T-SAT-71; NRC Examination Security Requirements; Revision 0
- FP-T-SAT-73; Licensed Operator Requalification Program Examinations; Revision 2
- CAP 01115710; Annual Operating Exam Security Lapse Results in Rework; dated November 1, 2007

1R12 Maintenance Rule Implementation

- WO 00331038; 1-P15A Casing Flange and Inboard Seal Leaks; October 29, 2008
- AR 01138734; 1P-15A Difficulties with Inboard Housing Dowels
- AR 01130678; HX-178B K-003B Intercooler Tubesheet Degradation
- AR 01101819; Abnormal Alignment May Be A Temporary Modification
- MRE 01114750; Moisture Coming Out Of The Unloader Exhaust Silencer
- MRE 01102651; T-180A Thru Wall Leak (K-003A Service Air Compressor)
- SE-0360 Work Order Search – Service Air; September 1, 2006 to October 1, 2008
- Maintenance Rule Performance Criteria; Service Air; November 14, 2005
- Maintenance Rule Performance Criteria; Safety Injection; November 22, 2004
- Maintenance Rule (a)(1) System Action Plan Checklist and Approval; June 4, 2008
- Maintenance Rule Function List; Service Air; October 6, 2008
- Performance Criteria Assessments for SA; September 1, 2006 to October 6, 2008
- Search of Service Air MR Evaluations; September 1, 2006 to September 1, 2008

- Search of Service Air Condition Reports; September 1, 2006 to October 1, 2008
- Service Air Report Data; September 2006 to September 2008
- Station Log Search for Service Air; September 18, 2006 to October 6, 2008
- Smart System Status Report for SI System; Status Date September 13, 2008

1R13 Maintenance Risk Assessments and Emergent Work Control

- NP 10.3.6; Shutdown Safety Review and Safety Assessment; Revisions 25, 26, 27, and 28
- 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
- NP 10.3.7; Online Safety Assessment; Revision 19
- U1R31 Reduced Inventory Orange Path Contingency Plan
- U1R31 Shutdown Safety Profile; All Revisions

1R15 Operability Evaluations

- AR 01136629; GL-2008-01 2SI-D06, D05, S06, S08, and 2RH-S09 UT Inspection
- CE 01136629; Disposition of Void in ECCS Piping; October 2, 2008
- AR 01140867; South Header Service Water Pumps Show Decline in Flow
- AR 01141059; Unauthorized Level Indication Marks on Oil Level Gauges
- AR 01138321; Degraded Bolting Due to Boric Acid Corrosion Identified on Unit 1 A and B RHR Heat Exchangers 1-HX-011A and 1-HX-011B
- AR 01139923; 1FM-03110 LEFM (Leading Edge Flow Meter) Failed
- CE 01139923; Evaluation for Unit 1 LEFM Operation for 100% RTO; November 18, 2008
- ACE 01139923; Unit 1 LEFM Was Found in a Failed State; December 18, 2008
- DBD-03; Condensate and Feedwater System; Revision 13
- EC 00012005; Transducer Pushrod Assembly (LEFM)

1R18 Plant Modifications

- Point Beach Unit 1 Updated Deposit Characterization and Deposit Loading Estimate; Revision 0
- Point Beach Unit 1 Steam Generator Chemical Cleaning Process Qualification Test; Revision 0

1R19 Post-Maintenance Testing

- WO 00331038; 1-P15A Casing Flange and Inboard Seal Leaks; October 29, 2008
- WO 00362010; Inspect, Document Field Condition of Blots in Lateral Restraint #13, and Replace Bolts with Proper Pre-Torque Tension Values
- RMP 9005-2; Safety Injection Pump Overhaul; Revision 10
- AR 01138803; Problems With SI Pump Rebuilds
- AR 01138686; 1P-15A Inboard Bearing Housing Dowel Pins to [sic] Loose
- AR 01138534; 1P-015A, SI Pump Thrust Bearing Housing Inspection Unsat
- TS 30; High and Low Head Safety Injection Check Valve Leakage Test Unit 1; Revision 31; Performed November 8, 2008
- IT-290B; Overspeed Test Turbine; Revision 17; completion dated November 10, 2008
- IT-08A; Cold Start of Turbine Driven AFW Pump and Valve Test; Revision 49; completion dated 11/13/2008
- RMP 9332; Steam Driven Auxiliary Feedwater Pump Drain Trap Maintenance; Revision 8

- TS 39; Main Steam Isolation Valves Operability Trip Test Unit ; Revision 15
- TS 10; Local Leak Test of Containment Airlock Bulkheads and Penetrations; Revision 27
- IT 03A; RHR Pump and Valve Tests in DHR Mode (Cold Shutdown) Unit 1; Revision 24; completion dated 10/25/2008
- ECN 12669; Install Vent on 12”-SI-151R-2 at High Point
- WO 00356575; SI / Scoping Walkdown GL 08-01 Gas Void Project

1R20 Outage Activities

- AR 01137773; Piece of Stud and Nut Fell From Above
- AR 00597442; Gore-Tex Gasket Material Found In Seat / Orifice Area of 1-D
- AR 01139651; Discrepancy in Debris Interceptor B3
- AR 01137061; Pressurizer Cold Calibration LT-433 Did Not Respond as Expected
- AR 01138671; Containment Equipment Hatch Trolley, 1Z-018, Trolley Wheel Fractured
- AR 01139687; Boric Acid Residue Seen in Gap Between Cavity and RPV
- AR 01147336; Inaccurate Pressurizer Level Indication
- AR 01057060; Pressurizer Level Indication Problems During RCS Draining
- AR 00594116; Inconsistent Response PZR Cold Cal Level Transmitter
- AR 01138315; Split Project Anomalies from Westinghouse
- AR 01138310; Split Pin FOSAR Finding
- AR 01137773; Piece of Stud Nut Fell From Above When Positioning Z-013
- AR 01126829; Adequacy of RCS Vent Path Questioned
- EE-2008-012; Engineering evaluation of Pressurizer Manway Foreign Material Exclusion Cover
- ACE 01137773; Unit 1 Polar Crane Girder Support Bracket Bolt Fractures and Fell
- EC 12884; Missing Bolt in the Polar Crane Lateral Support Connection; Revision 1
- ENG/JB-CSI-08-027; Preliminary Failure Analysis of PBNP 1 Polar Crane Bolt; October 23, 2008
- Engineering Evaluation; Polar Crane Bracket Bolt Preliminary Disposition
- 1 RMP 9118-1; Containment Building Crane OSHA Operability Inspections
- Boric Acid Leakage and Corrosion Monitoring Program; Revision 4
- NP 7.4.14; Boric Acid Leakage and Corrosion Monitoring
- Licensee Response to Generic Letter 88-05; dated May 24, 1988
- CL 4D; Outage Valve Inspection Unit 1; Revision 7
- OP 3A; Power Operation to Hot Standby Unit 1; Revision 1
- OP 3B; Reactor Shutdown; Revision 39
- OP 1A; Cold Shutdown to Hot Standby; Revision 95
- OP 1B; Reactor Startup; Revision 58
- OP 1C; Startup to Power Operation Unit 1; Revision 16
- OP 2A; Normal Power Operation; Revision 64
- OP 3C; Hot Standby to Cold Shutdown; Revision 106
- OP 4A; Filling and Venting the Reactor Coolant System; Revision 73
- OP 4D Part 1; Draining the Reactor Coolant System; Revision 76
- OP 4D Part 3; Draining the Reactor Cavity and Reactor Coolant System; Revision 26
- OP 4F; Reactor Coolant System Reduced Inventory Requirements; Revision 12
- OP 4G; Steam Generator Nozzle Dam Operational Requirements; Revision 4
- OP 5A; Reactor Coolant Volume Control; Revision 42
- OP 13A; Secondary Systems Startup; Revision 76
- OP 13B; Secondary Systems Shutdown; Revision 28
- RP 1A; Preparation for Refueling; Revision 79
- OI 11; Steam Generator Nozzle Dam Operation Guide; Revision 9

- NP 7.7.14; Reactor Vessel Integrity Program; Revision 6
- NP 1.2.6; Infrequently Performed Tests or Evolutions (IPTEs); Revision 14
- SLP 2; Safe Load Path and Rigging Manual; Revision 20
- SEM 7.11.9; Installation of Steam Generator Nozzle Dams Unit 1; Revision 6
- RP 1C; Refueling; Revision 64
- RMP 9030; Unit 1 and Unit 2 Pressurizer Manway Cover Removal and Installation; Revision 14
- 1RMP 9096-1; Reactor Vessel Head Removal and Installation Using Biach Tensioning System
- 0-SOP-FH-001; Fuel/Insert/Component Movement in the Spent Fuel Pool; Revision 14
- FP-OP-ROM-01; Refueling Outage Management; Revision 3
- CL 2A; Defueled to Mode 6 Checklist for U1R31; Revision 11
- CL 2B; Mode 6 to Mode 5 Checklist for U1R31; Revision 10
- CL 2C; Mode 5 to Mode 4 Checklist for U1R31; Revision 14
- CL 2D; Mode 4 to Mode 3 Checklist for U1R31; Revision 11
- CL 2E; Mode 3 to Mode 2 Checklist for U1R31; Revision 15
- CL 2F; Mode 2 to Mode 1 Checklist for U1R31; Revision 15
- Outage Additions and Deletions for U1R31
- U1R31 Reduced Inventory Orange Path Contingency Plan
- U1R31 Shutdown Safety Profile; All Revisions
- FP-PE-PM-01; Preventive Maintenance Program; Revision 3
- NP-910; Plant Readiness for Operations Prior to Restart U1R31 Refueling Outage
- REI 52.0; Core Map/Gap Check Instructions; Revision 0
- NP 1.2.6; Infrequently Performed Test or Evolutions (IPTEs); Revision 14

1R22 Surveillance Testing

- RESP 1.2; Rod Control System: Rod Position Verification and Rod Position Indicator Alignment; Revision 10; Performed November 12, 2008
- AR 01139382; 1P-2B 1B52-13B Failed to Strip During U1 ORT-3A
- AR 01139357; Field Voltage Recorded Reading Below Acceptance Criteria
- ORT 3A; Safety Injection Actuation With Loss of Engineered Safeguards AC (Train A) Unit 1; Revision 42
- ORT 3B; Safety Injection Actuation With Loss of Engineered Safeguards AC (Train B) Unit 1; Revision 39
- EC 13025; Evaluation of ORT 3A and 3B Unit 1 Results; November 8, 2008

1EP4 Emergency Action Level and Emergency Plan changes

- Point Beach Nuclear Plant Emergency Plan Manual; Section 7.0; Revisions 51 and 52
- Point Beach Nuclear Plant Emergency Plan Manual; Appendix A; Revisions 26 and 27
- 10 CFR 50.54 (q) Review Form; QF0724 R01; Revisions 52 and 57

2OS1 Access Control to Radiologically Significant Areas; and
2OS2 ALARA Planning and Controls

- AR 01108316; Little Guidance Exists in Procedures for VHRA Access Limits
- AR 01112896; Improvements in Posting and Access Control to ALPs
- AR 01119059; Recent Changes to RP Procedures
- AR 01120599; RP Has Not Implemented EPRI Alpha Monitoring Recommendations
- AR 01120634; Radiological Posting in Plant Is Overly Conservative
- AR 01127857; Unit 2 Fuel Movement Postings

- AR 01136293; Radiation Area Postings
- AR 01136743; Locked High Radiation Area Floor Plugs Not Clearly Labeled
- AR 01136788; Two Individuals Sign into Correct RWP but Wrong Task
- AR 01136794; RWP Violation
- Auxiliary Operator Qualification Status Matrix; dated October 09, 2008
- PBF-4246; Radiological Pre-Job Briefing Form; Revision 01
- HP 2.14; Containment Keyway Personnel Access; Revision 14
- HP 3.2; Health Physics Manual; Radiological Labeling, Posting and Barricading Requirements; Revision 48
- HP 3.2.10; Secure High Radiation Area Controls; Revision 01
- NP 4.2.19; Entry Requirements into Radiologically Controlled Areas; Revision 13
- TRPR 17.0; Point Beach Auxiliary Operator Training Program Description; Revision 34
- TRQM 17.31; Auxiliary Operator Health Physics; Revision 12

<u>2PS1 Radioactive Gaseous and Liquid Effluent Treatment and Monitoring Systems</u>

- Point Beach Nuclear Plant Annual Monitoring Report for 2006 (issued April 28, 2007) and for 2007 (issued April 30, 2008)
- Point Beach Nuclear Plant Offsite Dose Calculation Manual; Revision 18
- Point Beach Nuclear Plant Radiological Effluent Control Manual; Revision 4
- Point Beach Nuclear Plant EPIP 1.2.1; Emergency Action Level Technical Basis; Revision 2
- HPCAL 3.4; Calibration for U-1 Containment Purge Vent SPING; dated September 26, 2007
- HPCAL 3.4; Calibration for U-2 Containment Purge Vent SPING; dated June 23, 2008
- HPCAL 3.4; Calibration for Auxiliary Building Vent SPING; dated February 11, 2008
- HPCAL 3.4; Calibration for Drumming Area Vent SPING; dated October 9, 2007
- HPCAL 3.8; Calibration for Auxiliary Building Vent Stack Monitor; dated June 21, 2007
- HPCAL 3.12 Calibration for Air Ejector Vent Monitor; dated September 2, 2008
- HPCAL 3.12; Calibration for Condenser Air Ejector Vent Monitor; dated January 23, 2008
- HPCAL 3.8; Calibration for Drumming Area Vent Stack Monitor; dated July 16, 2008
- HPCAL 3.8; Calibration for Gas Stripper Building Vent Monitor; dated July 15, 2008
- HPCAL 3.1; Calibration for U-2 Service Water Monitor; dated January 14, 2008
- HPCAL 3.1; Calibration for U-1 Service Water Monitor; dated September 25, 2008
- HPCAL 3.1; Calibration for Radwaste Discharge Monitor; dated July 17, 2008
- HPCAL 3.13; Calibration for U-1 Steam Generator Blowdown Monitor; dated August 12, 2008
- AR 01127172; Validation of Point Beach Nuclear Plant 2007 Annual Monitoring Report; dated May 1, 2008
- AR 01130468; Radiation Monitoring System Obsolescence
- AR 01117730; Radiation Monitoring System Health Status Change
- AR 01108334; Radioiodine Results High – Evaluate for Annual Monitoring Report Impact
- AR 01134220; Groundwater Monitoring Program Self-Assessment Actions
- AR 01116926 (plus numerous other ARs for similar issues); Failed Count Room Detector QC; various; dates in 2007 and 2008
- RAM 5.1; Radioactive Airborne Effluent Releases; Revision 10
- CAMP 031; Preparation of Batch Liquid and Gaseous Effluent Permits Using RETSCODE Software; Revision 7
- RMS System Health Report; dated December 6, 2007
- HPIP 3.52.1; Radiological Sampling for Release Accountability; Revision 26
- Results of Gamma Spectroscopy System Daily Performance Checks; selected dates between June 2007 and October 2008
- Results of Point Beach Nuclear Plant Inter-laboratory Radiological Crosscheck Program; dated April 12, 2007

- Ventilation System Filter In-Situ Test Results for Unit-1/2 Containment Purge Exhaust and Auxiliary Building Vent Stack; dated June 23, 2008 (and associated laboratory radioiodine penetration test reports; dated August 18 and 19, 2008)
- NP 3.2.1; Point Beach Nuclear Plant Analytical Quality Assurance Program; Revision 14
- CAMP 310; Operation of the Canberra Genie 2000/Procount Gamma Spectroscopy Counting System; Revision 6
- Florida Power & Light Self-Assessment Report; NEI Industry Groundwater Protection Initiative; dated August 6, 2008
- Point Beach Nuclear Oversight Assessment Report; NEI 07-07 – Industry Groundwater Protection Initiative; dated June 26, 2008

4OA1 Performance Indicator Verification

- Point Beach Nuclear Plant Effluent Dose Estimate Summary Data and Quarterly NRC Performance Indicator Results; dated November 2007 and September 2008
- Point Beach Nuclear Plant Liquid and Gaseous Effluent Monthly Data Inputs; dated December 2007, March 2008 and September 2008

4OA2 Problem Identification and Resolution

- FP-PA-ARP-01; CAP Action Request Process; Revision 24
- PI-AA-205; Condition Evaluation and Corrective Action; Revision 0
- PI-AA-204; Condition Identification and Screening Process; Revision 1
- Condition Reports initiated between October 1, 2008 and December 31, 2008
- NP 2.1.4; Operator Burdens; Revision 9
- OWA Full Detail Report; As of December 1, 2008

4OA3 Follow-up of Events and Notices of Enforcement Discretion

- Point Beach Calculation 2000-0001; RCS Pressure-Temperature Limits and LTOP Setpoints Applicable Through 32.2 EFPY – Unit 1 and 34.0 – Unit 2; March 6, 2000
- AR 01114739; LTOP Setpoint may be Non-Conservative
- AR 01116679; LTOP Setpoint Basis Calculation Discrepant Value
- Westinghouse Letter WEP-07-7; Transmittal of Final WCAP-16669-WP, “Pressure Temperature Limit Curves,” LTOPS Final Report, and PTLR Markup; February 1, 2007
- Westinghouse Letter WEP-04-17; Low Temperature Overpressure Protection System (LTOPS) Setpoint Report; February 4, 2007

4OA5 Other Activities

- O-PT-EDG-011; G-01 Emergency Diesel Generator Endurance and Margin Testing Revision 2
- O-PT-EDG-021; G-02 Emergency Diesel Generator Endurance and Margin Testing; Revision 0
- O-PT-EDG-031; G-03 Emergency Diesel Generator Endurance and Margin Testing; Revision 0
- O-PT-EDG-041; G-04 Emergency Diesel Generator Endurance and Margin Testing
- Calculation 2004-0002; Emergency Diesel Steady State Loading Analysis; Revision 2
- RCE 01092944-01; Apparent Noncompliance with TS 5.6.5.c (PTLR)
- Letter from NRC to NMC; Acceptance of Methodology for Referencing Pressure Temperature Limits Report; July 23, 2001

- Letter from NMC to NRC 2003-0108; Revision of Pressure Temperature Limits Expiration Dates; November 7, 2003
- Letter from NMC to NRC 2006-090; License Amendment Request 251 – Technical Specification 5.6.5, Reactor Coolant System Pressure and Temperature Limits Report (Request for use of FERRET Code), December 14, 2006
- Letter from FP&L to NRC 2007-0092, Revision 2 of the Pressure and Temperature Limits Report for Point Beach Nuclear Plant - Units 1 and 2, Rev 2; November 15, 2007
- AR 906927; Reactor Vessel Fluency Discrepancy (PTLR)
- AR 906927-01; OPR 000175 Rev 0
- Westinghouse report WCAP-15976; Point Beach Unit 1 and 2 Heatup and Cooldown Curves for Normal Operations, February 13, 2003
- WEP 04-107 (LTR-REA-04-64); NMC PBNP Units 1 and 2 Aging Management Blanket Task 15, Reactor Vessel Additional Information; June 4, 2004
- AR 00195931-01/CA 025553; Review CAP028414 and Implement Recommendations (closed January 29, 2004)
- AR 00532499/CA 052717; Issue New PT Curves Documented in WCAP15976 into PTLR (closed August 27, 2004)
- AR 00195931-01-CA 060220; Document the Annual PTLR Applicability in year 2005 (closed June 1, 2005)

LIST OF ACRONYMS USED

AC	Alternating Current
ADAMS	Agencywide Documents Access and Management System
AFW	Auxiliary Feedwater
ALARA	As-Low-As-Is-Reasonably-Achievable
AR	Action Request
ASME	American Society of Mechanical Engineers
BALCM	Boric Acid Leakage and Corrosion Monitoring
BI	Barrier Integrity
CAP	Corrective Action Program
CFR	Code of Federal Regulations
CVC	Chemical and Volume Control System
DRS	Division of Reactor Safety
ECCS	Emergency Core Cooling System
EC	Eddy Current
EFPY	Effective Full Power Years
EPRI	Electric Power Research Institute
FSAR	Final Safety Analysis Report
IMC	Inspection Manual Chapter
IP	Inspection Procedure
ISI	Inservice Inspection
IST	Inservice Testing
LER	Licensee Event Report
LLD	Lower Limit of Detection
LTOP	Low Temperature Overpressure Protection
MSPI	Mitigating Systems Performance Index
NCV	Non-Cited Violation
NDE	Non-Destructive Examination
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
ODCM	Offsite Dose Calculation Manual
OWA	Operator Workaround
PARS	Publicly Available Records System
PI	Performance Indicator
POS	Plant Operating State
PRA	Probabilistic Risk Analysis
PSIG	Pounds Per Square Inch - Gauge
PTLR	Pressure and Temperature Limits Report
PWSCC	Primary Water Stress Corrosion Cracking
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RECM	Radiological Effluent Control Manual
RETS	Radiological Effluent Technical Specifications
RHR	Residual Heat Removal
RWP	Radiation Work Permit
SDP	Significance Determination Process
SER	Safety Evaluation Report
SFPC	Spent Fuel Pool Cooling System
SG	Steam Generator
SI	Safety Injection

SRA	Senior Reactor Analyst
TRM	Technical Requirements Manual
TS	Technical Specification
U1R31	Unit 1 Refueling Outage – Cycle 31
URI	Unresolved Item
UT	Ultrasonic Examination
VT	Visual Exam
WO	Work Order