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

February 10, 2011

Mr. Larry Meyer
Site Vice President
NextEra Energy Point Beach, LLC
6610 Nuclear Road
Two Rivers, WI 54241

SUBJECT: POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2 NRC INTEGRATED INSPECTION REPORT 05000266/2010005; 05000301/2010005

Dear Mr. Meyer:

On December 31, 2010, 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 results of this inspection, which were discussed on January 4, 2011, with you and other 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 personnel.

Based on the results of this inspection, four NRC-identified and two self-revealed findings of very low safety significance were identified. The findings involved 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 2.3.2 of the NRC Enforcement Policy. Additionally, a licensee-identified violation is listed in Section 4OA7 of this report.

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 addition, if you disagree with the cross-cutting aspect assigned to any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region III, and the NRC Resident Inspector at the Point Beach Nuclear Plant.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records System (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Website 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 05000266/2010005; 05000301/2010005
w/Attachment: Supplemental Information

cc w/encl: Distribution via ListServ

U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	05000266; 05000301
License Nos:	DPR-24; DPR-27
Report No:	05000266/2010005; 05000301/2010005
Licensee:	NextEra Energy Point Beach, LLC
Facility:	Point Beach Nuclear Plant, Units 1 and 2
Location:	Two Rivers, WI
Dates:	October 1, 2010, through December 31, 2010
Inspectors:	S. Burton, Senior Resident Inspector R. Ruiz, Resident Inspector P. Cardona-Morales, Reactor Engineer K. Carrington, Reactor Engineer M. Phalen, Senior Health Physicist M. Garza, Emergency Response Specialist D. Chyu, Regional Inspector R. Krsek, Senior Resident Inspector, Kewaunee K. Barclay, Resident Inspector, Kewaunee D. McNeil, Senior Operations Engineer
Approved by:	Michael A. Kunowski, Chief Branch 5 Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000266/2010005, 05000301/2010005; 10/01/10 – 12/31/10; Point Beach Nuclear Plant, Units 1 & 2; Surveillance Testing; Problem Identification and Resolution; and Follow-Up of Events and Notices of Enforcement Discretion.

This report covers a three-month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. Six Green findings were identified by the inspectors. The six findings were considered non-cited violations (NCVs) of NRC regulations. 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 non-cited violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was self-revealed when an auxiliary operator failed to correctly perform a procedure step. Specifically, OP-3A, "Power Operation to Hot Standby Unit 1," step 5.11.7 directed the auxiliary operator to ensure the turbine crossover steam dump valves were closed. However, the auxiliary operator misread the position indication for the valves as closed, when, in fact, the valves were open. Because the valves were never closed, an uncontrolled lowering of condenser vacuum occurred, requiring licensed operators to trip the reactor. The licensee initiated a condition report, performed an apparent cause evaluation, and initiated corrective actions to address the issues identified in the causal evaluation.

  The finding was determined to be more than minor because it was associated with the Initiating Events Cornerstone attribute of Human Performance and adversely 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, the failure to follow the procedure resulted in a reactor trip. The finding was determined to be of very low safety significance because the inspectors answered "no" to the Initiating Events Cornerstone Transient Initiator questions. The finding has a cross-cutting aspect in the area of human performance, work practices, because operations personnel did not utilize human performance error prevention techniques. Specifically, operations personnel failed to follow standards for pre-job briefs, verification and validation, and self-checks (H.4(a)). (Section 4OA3.6)

Cornerstone: Mitigating Systems

- Green. 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," was identified by the inspectors for the licensee's failure to establish adequate instructions or appropriate acceptance criteria to ensure that voids vented from safety-related piping were evaluated for their effects on system operability. The licensee entered the issue into its corrective action program, performed a condition evaluation, and took actions to revise the deficient procedure.

The issue was more than minor because the lack of procedural controls for void monitoring and assessment resulted in a condition where there was reasonable doubt that the past operability of the system was properly assessed, and that these observations, if left uncorrected, could lead to a condition where an inoperable system or gas intrusion mechanisms would not be identified or corrected. The finding was of very low safety significance, because the inspectors answered "no" to all of the questions in the Mitigating Systems Cornerstone column of the Significance Determination Process worksheet. The inspectors determined that the finding has a cross-cutting aspect in the area of human performance, decision-making, because the interdisciplinary nature of the observations reflected a lack of a systematic process during the development and execution of the related procedure (H.1(a)). (Section 1R22.1.(1))

- <u>Green</u>. 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," was identified by the inspectors for the licensee's failure to perform ultrasonic testing on safety-related systems for void assessment as required by the licensee's gas accumulation management program. The licensee entered the issue into its corrective action program and has begun the required ultrasonic testing.

  The issue was more than minor because the lack of procedural controls for void monitoring and assessment resulted in a condition where there was reasonable doubt that the past operability of the system was properly assessed, and that these observations, if left uncorrected, could lead to a condition where an inoperable system or gas intrusion mechanisms would not be identified or corrected. The issue was determined to be of very low safety significance because the inspectors answered "no" to all of the questions in the Mitigating Systems Cornerstone column of the Significance Determination Process worksheet. The inspectors determined that the finding has a cross-cutting aspect in the area of human performance, work practices, because the licensee failed to provide sufficient oversight to ensure that the procedure was followed (H.4(c)). (Section 1R22.1.(2))

- <u>Green</u>. 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," was self-revealed for the failure to have adequate maintenance procedures for calibrating the engineered safety features actuation system steam line pressure dynamic compensation modules. Specifically, since the basis calculation for determining the settings of the lead/lag values for the modules did not address dynamic settings, and the proceduralized tolerances were too restrictive, the calibration instructions were inadequate to ensure the modules' ability to perform in accordance with technical specification requirements. Upon discovery, the licensee entered the issue into its corrective action program and performed an apparent cause evaluation that documented a number of planned program and procedural enhancements.

  The finding was more than minor because it is associated with the equipment performance attribute of the Mitigating Systems Cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The finding was determined to be of very low safety significance because there was no design deficiency, no actual loss of safety function, no single train loss of safety function for greater than the technical specification allowed outage time, and no risk due to external events. The finding does not have a cross-cutting aspect because the performance deficiency occurred outside of the 3-year window considered to be representative of present performance. (Section 4OA3.2)

- Green, SL-IV. A Severity Level IV non-cited violation of 10 CFR 50.59(d)(1), "Changes, Tests, and Experiments," was identified by the inspectors for the failure to document an evaluation that provided a basis for the determination that the changes made to procedure OI-38, "Circulating Water System Operation," did not require a license amendment. Specifically, the licensee failed to provide an evaluation that adequately documented that differences between the procedure changes modifying the operational configuration of the condenser steam dump system and operational considerations and design assumptions outlined within the final safety analysis report and the basis of technical specifications were acceptable. As part of its corrective action, the licensee revised the procedure to remove the original change to the operational configuration of the steam dump system.

  The violation was determined to be more than minor because the inspectors could not reasonably determine that the changes would not have ultimately required prior NRC approval. Violations of 10 CFR 50.59 are dispositioned using the traditional enforcement process instead of the Reactor Oversight Process Significance Determination Process (SDP) because they are considered to be violations that could potentially impede or impact the regulatory process. The underlying technical issue was evaluated under the SDP to determine the significance of the violation with respect to core damage probability. The issue screened as having very low safety significance because the inspectors answered "no" to all of the questions in the SDP worksheet. The finding has a cross-cutting aspect in the corrective action program element of problem identification and resolution because the licensee failed to thoroughly evaluate questions regarding differences between the plant operational configuration and assumptions in the current licensing basis when they did not complete a prompt operability evaluation to assess noted operational disparities (P.1(c)). (Section 4OA3.4)

Cornerstone: Other Findings

- SL IV. A Severity Level IV non-cited violation of 10 CFR Part 50.73(a)(2)(v)(A) and (D) was identified by the inspectors for the failure of the licensee to report an event or condition that could have prevented the fulfillment of the auxiliary feedwater and safety injection safety functions, which are relied upon to shutdown the reactor and maintain it in a shutdown condition, and mitigate the consequences of an accident. Specifically, the licensee had not properly controlled the blocking open of doors that served as high energy line break barriers. The licensee entered the violation into its corrective action program as condition report 01616620 and revise the procedure on control of high energy line break barriers.

  Violations of 10 CFR 50.73 are considered to be violations that potentially impact the regulatory process and are dispositioned using the traditional enforcement process instead of the Reactor Oversight Process Significance Determination Process. A cross-cutting aspect was not assigned to this violation. (Section 4OA2.3)

B. Licensee-Identified Violations

Violations of very low safety significance that were identified by the licensee have been reviewed by inspectors. Corrective actions planned or taken by the licensee have been entered into the licensee's corrective action program. These violations and corrective action tracking numbers are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at 100 percent power throughout the entire inspection period with the exception of a planned downpower to 68 percent power on October 31, 2010, for turbine trip and stop valve testing, and a small power reduction for additional routine surveillance testing.

Unit 2 operated at 100 percent power throughout the entire inspection period with the exception of a small power reduction for routine surveillance testing, and an unplanned outage from December 13 through December 21, 2010, as a result of control rod drive system issues.

1. REACTOR SAFETY

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

1R01 Adverse Weather Protection (71111.01)

.1 Winter Seasonal Readiness Preparations

a. Inspection Scope

The inspectors conducted a review of the licensee's preparations for winter conditions to verify that the plant's design features and implementation of procedures were sufficient to protect mitigating systems from the effects of adverse weather. Documentation for selected risk-significant systems was reviewed to ensure that these systems would remain functional when challenged by inclement weather. During the inspection, the inspectors focused on plant specific design features and the licensee's procedures used to mitigate or respond to adverse weather conditions. Additionally, the inspectors reviewed the Final Safety Analysis Report (FSAR) and performance requirements for systems selected for inspection, and verified that operator actions were appropriate as specified by plant specific procedures. Cold weather protection, such as heat tracing and area heaters, was verified to be in operation where applicable. The inspectors also reviewed corrective action program (CAP) items to verify that the licensee was identifying adverse weather issues at an appropriate threshold and entering them into the CAP in accordance with station corrective action procedures. Specific documents reviewed during this inspection are listed in the Attachment to this report. The inspectors' reviews focused specifically on the following plant systems due to their risk significance or susceptibility to cold weather issues:

- heat tracing system;
- ventilation systems, turbine building and primary auxiliary building; and
- diesel generators.

This inspection constituted one winter seasonal readiness preparations sample as defined in Inspection Procedure (IP) 71111.01-05.

b. Findings

No findings were identified.

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

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

- turbine-driven auxiliary feedwater (TDAFW) pump 2P29.

The inspectors selected this system based on its risk significance relative to the Reactor Safety Cornerstones at the time it was 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 FSAR, technical specification (TS) requirements, outstanding work orders (WOs), condition reports (CRs), and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have rendered the system incapable of performing its intended functions. The inspectors also walked down accessible portions of the system 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 to this report.

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

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

The inspectors conducted fire protection walkdowns which were focused on availability, accessibility, and the condition of firefighting equipment in the following risk-significant plant areas:

- fire zone 596, Unit 2 façade;
- fire zone 770, emergency diesel generator (EDG) G-03;
- fire zone 773, EDG G-03, switchgear; and
- fire zone 777, EDG G-04, switchgear.

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 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 as documented in the plant's Individual Plant Examination of External Events with later additional insights, their potential to impact equipment which could initiate or mitigate a plant transient, or their impact on the plant's ability to respond to a security event. Using the documents listed in the Attachment to this report, 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 that 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 four quarterly fire protection inspection samples as defined in IP 71111.05-05.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Resident Inspector Quarterly Review (71111.11Q)

a. Inspection Scope

On November 2, 2010, the inspectors observed a crew of licensed operators in the plant's simulator during licensed operator requalification examinations to verify that: operator performance was adequate; evaluators identified and documented crew performance problems; and training was 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 (EP) actions and notifications.

The crew's performance in these areas was compared to pre-established operator action expectations and successful critical task completion requirements. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings were identified.

.2 Examination Security

a. Inspection Scope

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

b. Findings

During the annual operating examination on September 28, 2010, there was an examination security event. While the crew walked down the control boards for the second scenario of the day, the shift manager discovered that the notepad on his desk had an equipment component annotated in the upper left hand corner of the notepad. Trainers verified the annotated piece of equipment related to the first event in the previous crew's scenario. The equipment identifier had been jotted down by an individual on the first crew in the morning during their scenario and the examination team had missed the notation on the notepad when they scrubbed the simulator following the first scenario. The shift manager took possession of the notepad and informed the operations manager, who was standing next to him. The page was then given to the continuing training supervisor on the simulator floor. Another crew member standing next to the continuing training supervisor saw a part of the equipment identification, but not the entire number. The examination team conferred and agreed to modify the scenario starting locations such that the shift manager and the other crew member would start the scenario under sequestration in another area (simulating attending a meeting in the work control center). After the scenario began and the first event was in progress, the shift manager and other crew member were called back to the control room and informed of the event by the crew. This prevented the partial information from affecting the crew response to the first event. It also resulted in no effect on the evaluation of competencies for the shift manager and the other crew member. Post-exam follow-up discussions with the crew validated that no one else had knowledge of the annotated page on the shift manager's desk. It was determined that no examination compromise occurred.

No findings were identified.

.3 Biennial Written and Annual Operating Test Results (71111.11B)

a. Inspection Scope

The inspector reviewed the overall pass/fail results of the individual biennial written examinations, the overall pass/fail results of the individual Job Performance

Measure operating tests, and the simulator operating tests (required to be given per 10 CFR 55.59(a)(2)) administered by the licensee from August 16, 2010, through October 29, 2010, as part of the licensee's operator licensing requalification cycle. These results were compared to the thresholds established in IMC 0609, Appendix I, "Licensed Operator Requalification Significance Determination Process (SDP)." The evaluations were also performed to determine if the licensee effectively implemented operator requalification guidelines established in NUREG-1021, "Operator Licensing Examination Standards for Power Reactors," and IP 71111.11, "Licensed Operator Requalification Program." Documents reviewed are listed in the Attachment to this report.

Completion of this section constituted one biennial licensed operator requalification inspection sample as defined in IP 71111.11B.

b. Findings

No findings 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:

- TDAFW pump 2P29.

The inspectors reviewed events, such as where ineffective equipment maintenance had resulted in valid or invalid automatic actuations of engineered safeguards systems, and independently verified the licensee's actions to address system performance or condition problems 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 (SSCs)/functions classified as (a)(2), or appropriate and adequate goals and CAs 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 to this report.

This inspection constituted one quarterly maintenance effectiveness sample as defined in IP 71111.12-05.

b. Findings

No findings were identified.

1R15 Operability Evaluations (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- residual heat removal (RHR) test, return isolation valve difficult to operate;
- containment spray pump 2P14B seal heat exchanger crack; and
- containment spray pump seal coolers not rated for component cooling water (CCW) pressure.

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 reviewed a sampling of CA documents to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings were identified.

1R18 Plant Modifications (71111.18)

.1 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed the following temporary modification:

- modification to Unit 2 safety injection (SI) accumulator relief valves.

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

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

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19)

.1 Post-Maintenance Testing

a. Inspection Scope

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

- transfer bus duct jumper replacement on transformer 1X01, Unit 1;
- SI accumulator relief valve, Unit 2;
- EDG G-04 after biennial maintenance outage, Unit 2;
- TDAFW 2P29, Unit 2; and
- service water (SW) pump D testing after modifications and maintenance, Unit 2.

These activities were selected based upon the SSCs' 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 (temporary modifications or jumpers required for test performance were properly removed after test completion); and test documentation was properly evaluated. The inspectors evaluated the activities against 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 basis and design requirements. In addition, the inspectors

reviewed CA documents associated with PM 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 to this report.

This inspection constituted five post-maintenance testing samples as defined in IP 71111.19-05.

b. Findings

No findings were identified.

1R20 Outage Activities (71111.20)

.1 Other Outage Activities

a. Inspection Scope

The inspectors evaluated outage activities during an unscheduled outage on Unit 2 from December 13 through 21, 2010. The licensee shut down Unit 2 from 100 percent power on December 13 after a surveillance test of the rod control system could not be completed in the allotted time. The test had been scheduled near the end of the surveillance frequency period and after one of the control rods developed a problem during the test, the time to complete the test had expired. On December 15, after troubleshooting and some repair activities, the licensee attempted to restart the reactor but aborted the startup in Mode 2 when additional rod control system alarms were received and several (but not all) rod groups automatically fell into the core. The rod control system vendor then conducted extensive additional testing of the system and repaired or replaced various components. After additional testing, the licensee restarted the reactor on December 21.

The inspectors observed or reviewed the reactor shutdown, outage equipment configuration and risk management, electrical lineups, selected clearances, control and monitoring of decay heat removal, control of containment activities, startup activities, and identification and resolution of problems associated with the outage. The inspectors reviewed activities to ensure that the licensee considered risk in developing, planning, and implementing the outage schedule.

This inspection constituted one other outage sample as defined in IP 71111.20-05.

b. Findings

No findings were identified.

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:

- low head SI pump and valve test (inservice test (IST));
- EDG G-04 monthly test; and
- emergency core cooling system (ECCS) venting and ultrasonic testing (UT) (IST).

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 frequency was in accordance with TSs, the FSAR, procedures, and applicable commitments;
- measuring and test equipment calibration was current;
- test equipment was used within the required range and accuracy; applicable prerequisites described in the test procedures were satisfied;
- test frequencies met TS requirements to demonstrate operability and reliability; tests were performed in accordance with the test procedures and other applicable procedures; jumpers and lifted leads were controlled and restored where used;
- test data and results were accurate, complete, within limits, and valid;
- test equipment was removed after testing;
- where applicable for inservice testing activities, testing was performed in accordance with the applicable version of Section XI, American Society of Mechanical Engineers (ASME) code, and reference values were consistent with the system design basis;
- where applicable, test results not meeting acceptance criteria were addressed with an adequate operability evaluation or the system or component was declared inoperable;
- where applicable for safety-related instrument control surveillance tests, reference setting data were accurately incorporated in the test procedure;
- where applicable, actual conditions encountering high resistance electrical contacts were such that the intended safety function could still be accomplished;
- prior procedure changes had not provided an opportunity to identify problems encountered during the performance of the surveillance or calibration test;
- equipment was returned to a position or status required to support the performance of its safety functions; and
- all problems identified during the testing were appropriately documented and dispositioned in the CAP.

Documents reviewed are listed in the Attachment to this report.

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

b. Findings

(1) Inadequate Safety System Venting Procedure Void Assessment Requirements

Introduction: A finding of very low safety significance and associated non-cited violation (NCV) of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified by the inspectors for the licensee's failure to establish adequate instructions or appropriate acceptance criteria to ensure that voids vented from safety-related piping were evaluated for their effects on system operability.

Description: The inspectors selected procedure 2-TS-ECCS-002, "Safeguards System Venting (Monthly) Unit 2, Train B," performed on November 9, 2010, for review. The remarks section of this test noted that small bubbles were observed and that it took 16 minutes of venting to clear this condition. The inspectors reviewed several related condition reports (CRs); however, a CR specific to evaluating the volume of the vented gas had not been written. The inspectors inquired about the lack of a CR and the licensee indicated that it was because the procedural acceptance criteria had been met.

The gas accumulation management program (GAMP) procedure indicated that "surveillance tests and/or other procedures that direct the evaluation of a monitoring location shall provide a specific method for monitoring and calculating void size, and specify the void size criteria (both individual and cumulative) for alert and action levels, and operability limits." Step 4.5.2 of the GAMP required that "vented monitoring locations shall be trended for gas accumulation. Trending shall annotate circumstances associated with the venting (e.g., if venting for post-SDC [shutdown cooling] operation or if venting was performed following maintenance). This allows for better understanding of the volume of gas expected during the venting process, whether multiple venting activities are expected prior to complete removal of gas, and the mechanisms that result in gas accumulation." Also that, "Trends of gas void size or vent duration necessary to remove accumulated gas should be used to revise procedures to provide better guidance on establishing void free conditions." Additionally, step 4.6 required that CAs be initiated if the gas accumulation exceeds various criteria (listed in a table in the GAMP), the cause of the event be determined, and CAs be assigned to prevent recurrence.

Because a CR had not been written for the surveillance performed in November 2010, the inspectors reviewed two additional surveillances for this system where bubbles/air had been observed. For a surveillance performed on September 5, 2010, using procedure 2-TS-ECCS-002, the licensee noted that it took 45 minutes to vent observed bubbles and that AR01180440 had been written to evaluate the results. For a surveillance performed on October 10, intermittent bubbles were vented for 10 minutes, the accumulation of gas was listed as a known condition, and AR01180440 from the September surveillance test was referenced.

The inspectors concluded that 2-TS-ECCS-002 did not contain sufficient direction for the licensee to assess the volume of voids vented from the related piping. Examples of areas where the procedure did not contain proper controls included: the lack of a reference to the GAMP tables that provided the acceptance criteria and a requirement to compare the void volume to the acceptance criteria; that the use of an asterisk for generic letter (GL) 2008-01, "Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems," installed vent valves was ambiguous nor was it consistently used to point to the GAMP for vent points/locations that had acceptance criteria associated with them; that direction to notify the shift manager when bubbles were observed did not ensure that a CR was written or that the void magnitude was assessed and compared to the GAMP acceptance criteria by some other means; that directions when bubbles were observed lacked a requirement that the magnitude of the void be documented; and that trending of the magnitude of the void was a time-to-vent measurement and that this measurement was insufficient to quantify the magnitude of the void.

Analysis: The inspectors determined that the lack of procedural controls to ensure that void volumes were quantified, documented, assessed, and trended was a performance deficiency warranting further review. The inspectors concluded that the issue was more than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," dated December 24, 2009, because it was associated with the Mitigating Systems Cornerstone attribute of equipment performance and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the lack of procedural controls for void monitoring and assessment resulted in a condition where there was reasonable doubt that the past operability of the system was properly assessed, and that these observations, if left uncorrected, could lead to a condition where an inoperable system or gas intrusion mechanisms would not be identified or corrected.

The inspectors evaluated the finding in accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At Power Situations," dated January 10, 2008, Attachment 0609.04, Table 4a. The inspectors determined the issue to be of very low safety significance (Green) because they answered "no" to all of the questions in the Mitigating Systems Cornerstone column of the table.

The inspectors determined that the finding has a cross-cutting aspect in the area of human performance, decision-making, because the interdisciplinary nature of the observations reflected a lack of a systematic process during the development and execution of the related procedure (H.1(a)). Specifically, the observed deficiencies impacted procedural integration, control of design margins, problem identification and resolution, and managerial decision-making. The licensee's formal evaluation of the cause of the issue was in progress at the conclusion of the inspection period. The inspectors reviewed a tabletop licensing analysis of the issue and their preliminary observations coincided with the inspectors' conclusion.

Enforcement: Title 10 CFR 50, Appendix B, Criterion V, "Instruction, Procedures, and Drawings," requires that activities affecting quality be prescribed by documented instructions, procedures, or drawings of a type appropriate to the circumstances, and include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished. Contrary to this requirement, 2-TS-ECCS-002 did not contain adequate instructions or appropriate acceptance criteria for the licensee to ensure that voids vented from safety-related piping were evaluated for the effects on system operability.

The licensee entered this issue into the CAP as AR1184615, "SI Accumulator Leakage, Non-Performance of GAMP Requirements," to assess and correct the deficient procedure. Because this violation was of very low safety significance and was entered into the licensee's CAP, it is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy (NCV 05000266/2010005-01; 05000301/2010005-01, Inadequate Safety System Venting Procedure Void Assessment Requirements).

(2) Failure to Perform Ultrasonic Assessment of Safety System Voids as Required by Procedure

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 identified by the inspectors for the licensee's failure to perform UT on safety-related systems for void assessment as required by the GAMP.

Description: While reviewing procedure 2-TS-ECCS-002, "Safeguards System Venting (Monthly) Unit 2, Train B," performed on November 9, 2010, the inspectors identified that the GAMP, referenced in the procedure, required UT to be performed on specific locations of some safety systems. However, the licensee indicated to the inspectors that UT had not been performed since June 2010.

The inspectors determined through a review of the procedure and GL 2008-01 documentation that the GAMP was a 10 CFR 50, Appendix B procedure. Specifically, GL 2008-01 indicated that programs were required to ensure that the effects of gas accumulation were properly monitored and controlled, and that this was supported by multiple regulatory requirements including various quality assurance program requirements including Regulatory Guide (RG) 1.33. The inspectors reviewed the licensee's quality assurance topical report and found that Section A.7, "Regulatory Commitments," committed the licensee to the applicable portions of RG 1.33.

Section 4.3 of the GAMP required that certain (sentinel) points would be tested periodically to monitor for gas intrusion into the subject systems. Section 4.4.3 indicated that "following initial venting, the standard frequency for evaluating sentinel points is monthly," and, "if gas volume is below the assessment limit for four consecutive intervals, then the evaluation frequency can be reduced to the next lower category weekly to bi-weekly, bi-weekly to monthly, monthly to quarterly)." Section 4.4.2 indicated that, "if a risk location is shown to be water solid for four consecutive intervals then periodic evaluation can be discontinued."

The inspectors found that Section 4.3.3 did not contain guidance to exceed a quarterly requirement. Additionally, for vented points, Section 4.4 indicated that the maximum interval was semi-annual. Records for sentinel points also indicated that, for the locations reviewed, the system was not water solid and, therefore, suspension of the testing was not acceptable. The inspectors determined that the licensee failed to perform the required UT because the surveillances had been suspended and documentation for interval extension did not exist, nor did provisions exist to allow venting to exceed a quarterly, or, using the vented location criteria, a semi-annual interval.

Analysis: The inspectors determined that failure to perform UT of sentinel points as required by the GAMP was a performance deficiency warranting further review. The inspectors concluded that the issue was more than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," dated December 24, 2009, because it was associated with the Mitigating Systems Cornerstone attribute of equipment performance and adversely affected the cornerstone objective to ensure that availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the failure to assess accumulated voids in safety systems, if left uncorrected, could lead to a condition where an inoperable system or gas intrusion mechanisms would not be identified or corrected.

The inspectors evaluated the finding in accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At Power Situations," dated January 10, 2008, Attachment 0609.04, Table 4a. The inspectors determined the issue to be of very low safety significance (Green) because they answered "no" to all of the questions in the Mitigating Systems Cornerstone column of the table. Specifically, because the licensee had completed a prompt operability evaluation that supported continued operability, system performance was not impacted.

The inspectors determined that the finding has a cross-cutting aspect in the area of human performance, work practices, because the licensee failed to provide sufficient oversight to ensure that the procedure was followed (H.4(c)). Specifically, numerous CRs existed that questioned the suspension of the related UT and these reports were reviewed by multiple levels of management.

Enforcement: Title 10 CFR 50, Appendix B, Criterion V, "Instruction, Procedures, and Drawings," requires 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 this requirement, the licensee failed to perform UT on safety-related systems for void assessment as required by the GAMP.

The licensee entered this issue into the CAP as AR01186536, "TI-177, Gas Intrusion Inspection Follow-Up Discussion," to assess the observation and perform the missed testing. Because this violation was of very low safety significance and was entered into the licensee's CAP, it is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy (NCV 05000266/2010005-02; 05000301/2010005-02, Failure to Perform Ultrasonic Assessment of Safety System Voids as Required by Procedure).

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 (EP), Revision 24; EP Implementing Procedure 1.2.1, Revisions 4 and 5; and EP Implementing Procedure 1.2, Revision 48, were implemented. These documents 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 EP, and that the revised EP as changed continued 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 EP changes and a review of the Emergency Action Level (EAL) 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 EAL and EP changes inspection constituted one sample as defined in IP 71114.04-05.

b. Findings

No findings were identified.

1EP6 Drill Evaluation (71114.06)

.1 Training Observation

a. Inspection Scope

The inspectors observed a simulator training evolution for licensed operators on November 2, 2010, which required EP implementation by a licensee operations crew. This evolution was planned to be evaluated and included in performance indicator (PI) data regarding drill and exercise performance. The inspectors observed event classification and notification activities performed by the crew. The inspectors also attended the post-evolution critique for the scenario. The focus of the inspectors' activities was to note any weaknesses and deficiencies in the crew's performance and ensure that the licensee evaluators noted the same issues and entered them into the CAP. As part of the inspection, the inspectors reviewed the scenario package and other documents listed in the Attachment to this report.

This inspection of the licensee's training evolution with emergency preparedness drill aspects constituted one sample as defined in IP 71114.06-05.

b. Findings

No findings were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2RS5 Radiation Monitoring Instrumentation (71124.05)

This inspection constituted one complete sample as defined in IP 71124.05-05.

.1 Inspection Planning (02.01)

a. Inspection Scope

The inspectors reviewed the FSAR to identify radiation instruments associated with monitoring area radiological conditions, including airborne radioactivity, process streams, effluents, materials/articles, and workers. Additionally, the inspectors reviewed the instrumentation and associated TS requirements for post-accident monitoring instrumentation, including instruments used for remote emergency assessment.

The inspectors reviewed a listing of in-service survey instrumentation, including air samplers and small article monitors, along with instruments used to detect and analyze workers' external contamination. Additionally, the inspectors reviewed personnel contamination monitors and portal monitors, including whole-body counters, used to detect workers' internal contamination. The inspectors reviewed this list to assess whether an adequate number and type of instruments were available to support operations.

The inspectors reviewed licensee and third-party evaluation reports of the radiation monitoring program since the last inspection. These reports were reviewed for insights into the licensee's program and to aid in selecting areas for review ("smart sampling").

The inspectors reviewed procedures that govern instrument source checks and calibrations, focusing on instruments used for monitoring transient high radiological conditions, including instruments used for underwater surveys. The inspectors reviewed the calibration and source check procedures for adequacy and as an aid to smart sampling.

The inspectors reviewed the area radiation monitor alarm setpoint values and setpoint bases as provided in the TSs and the FSAR.

The inspectors reviewed effluent monitor alarm setpoint bases and the calculational methods provided in the offsite dose calculation manual (ODCM).

b. Findings

No findings were identified.

.2 Walkdowns and Observations (02.02)

a. Inspection Scope

The inspectors walked down effluent radiation monitoring systems, including at least one liquid and one airborne system. Focus was placed on flow measurement devices and all accessible point-of-discharge liquid and gaseous effluent monitors of the selected systems. The inspectors assessed whether the effluent/process monitor configurations aligned with ODCM descriptions and observed monitors for degradation and out-of-service tags.

The inspectors selected portable survey instruments in use or available for issuance and assessed calibration and source check stickers for currency as well as instrument material condition and operability.

The inspectors observed licensee staff performance as the staff demonstrated source checks for various types of portable survey instruments. The inspectors assessed whether high-range instruments were source checked on all appropriate scales.

The inspectors walked down area radiation monitors and continuous air monitors to determine whether they were appropriately positioned relative to the radiation sources or areas they were intended to monitor. Selectively, the inspectors compared monitor response (via local or remote control room indications) with actual area conditions for consistency.

The inspectors selected personnel contamination monitors, portal monitors, and small article monitors and evaluated whether the periodic source checks were performed in accordance with the manufacturer's recommendations and licensee procedures.

b. Findings

No findings were identified.

.3 Calibration and Testing Program (02.03)

Process and Effluent Monitors

a. Inspection Scope

The inspectors selected effluent monitor instruments (such as gaseous and liquid) and evaluated whether channel calibration and functional tests were performed consistent with radiological effluent TSs/ODCM. The inspectors assessed whether: the licensee calibrated its monitors with National Institute of Standards and Technology traceable sources; the primary calibrations adequately represented the plant nuclide mix; when secondary calibration sources were used, the sources were verified by the primary calibration; and the licensee's channel calibrations encompassed the instrument's alarm setpoints.

The inspectors assessed whether the effluent monitor alarm setpoints were established as provided in the ODCM and station procedures.

For changes to effluent monitor setpoints, the inspectors evaluated the basis for changes to ensure that an adequate justification existed.

b. Findings

No findings were identified.

Laboratory Instrumentation

a. Inspection Scope

The inspectors assessed laboratory analytical instruments used for radiological analyses to determine whether daily performance checks and calibration data indicated that the frequency of the calibrations was adequate and there were no indications of degraded instrument performance.

The inspectors assessed whether appropriate CAs were implemented in response to indications of degraded instrument performance.

b. Findings

No findings were identified.

Whole Body Counter

a. Inspection Scope

The inspectors reviewed the methods and sources used to perform whole body count functional checks before daily use of the instrument and assessed whether check sources were appropriate and aligned with the plant's isotopic mix.

The inspectors reviewed whole body count calibration records since the last inspection and evaluated whether calibration sources were representative of the plant source term and that appropriate calibration phantoms were used. The inspectors looked for anomalous results or other indications of instrument performance problems.

b. Findings

No findings were identified.

Post-Accident Monitoring Instrumentation

a. Inspection Scope

Inspectors selected containment high-range monitors and reviewed the calibration documentation since the last inspection.

The inspectors assessed whether an electronic calibration was completed for all range decades above 10 rem/hour, and whether at least one decade at or below 10 rem/hour was calibrated using an appropriate radiation source.

The inspectors assessed whether calibration acceptance criteria were reasonable, accounting for the large measuring range and the intended purpose of the instruments.

The inspectors selected two effluent/process monitors that were relied on by the licensee in its emergency operating procedures as a basis for triggering emergency action levels and subsequent emergency classifications, or to make protective action recommendations during an accident. The inspectors evaluated the calibration and availability of these instruments.

The inspectors reviewed the licensee's capability to collect high-range, post-accident iodine effluent samples.

As available, the inspectors observed electronic and radiation calibration of these instruments to verify conformity with the licensee's calibration and test protocols.

b. Findings

No findings were identified.

Portal Monitors, Personnel Contamination Monitors, and Small Article Monitors

a. Inspection Scope

For each type of these instruments used onsite, the inspectors assessed whether the alarm setpoint values were reasonable under the circumstances to ensure that licensed material was not released from the site.

The inspectors reviewed the calibration documentation for each instrument selected and discussed the calibration methods with the licensee to determine consistency with the manufacturer's recommendations.

b. Findings

No findings were identified.

Portable Survey Instruments, Area Radiation Monitors, Electronic Dosimetry, and Air Samplers/Continuous Air Monitors

a. Inspection Scope

The inspectors reviewed calibration documentation for at least one of each type of instrument. For portable survey instruments and area radiation monitors, the inspectors reviewed detector measurement geometry and calibration methods and had the licensee demonstrate use of its instrument calibrator as applicable. The inspectors conducted comparison of instrument readings versus an NRC survey instrument if problems were suspected.

As available, the inspectors selected portable survey instruments that did not meet acceptance criteria during calibration or source checks to assess whether the licensee had taken appropriate CA for instruments found significantly out of calibration (greater than 50 percent). The inspectors evaluated whether the licensee had evaluated the possible consequences of instrument use since the last successful calibration or source check.

b. Findings

No findings were identified.

Instrument Calibrator

a. Inspection Scope

As applicable, the inspectors reviewed the current output values for the licensee's portable survey and area radiation monitor instrument calibrator unit(s). The inspectors assessed whether the licensee periodically measures calibrator output over the range of the instruments used through measurements by ion chamber/electrometer.

The inspectors assessed whether the measuring devices had been calibrated by a facility using National Institute of Standards and Technology traceable sources and whether corrective factors for these measuring devices were properly applied by the licensee in its output verification.

b. Findings

No findings were identified.

Calibration and Check Sources

a. Inspection Scope

The inspectors reviewed the licensee's 10 CFR Part 61, "Licensing Requirements for Land Disposal of Radioactive Waste," source term to assess whether calibration sources used were representative of the types and energies of radiation encountered in the plant.

b. Findings

No findings were identified.

.4 Problem Identification and Resolution (02.04)

a. Inspection Scope

The inspectors evaluated whether problems associated with radiation monitoring instrumentation were being identified by the licensee at an appropriate threshold and were properly addressed for resolution in the licensee CAP. The inspectors assessed the appropriateness of the CAs for a selected sample of problems documented by the licensee that involve radiation monitoring instrumentation.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

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

4OA1 Performance Indicator Verification (71151)

.1 Safety System Functional Failures

a. Inspection Scope

The inspectors sampled licensee submittals for the Safety System Functional Failures PI for Unit 1 and Unit 2 for the fourth quarter 2009 through the third quarter 2010. To determine the accuracy of the reported PI data, PI definitions and guidance contained in the Nuclear Energy Institute (NEI) Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, and NUREG-1022, "Event Reporting Guidelines 10 CFR 50.72 and 50.73," were used. The inspectors reviewed the licensee's operator narrative logs, operability assessments, maintenance rule records, maintenance work orders, issue reports, and event reports for the period of October 2009 through September 2010 to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two safety system functional failures samples as defined in IP 71151-05.

b. Findings

No findings were identified.

4OA2 Identification and Resolution of Problems (71152)

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness, Public Radiation Safety, Occupational Radiation Safety, and Physical Protection

.1 Routine Review of Items Entered into the Corrective Action Program

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 entered into the licensee's CAP at an appropriate threshold, that adequate attention was given to timely CAs, and that adverse trends were identified and addressed. Attributes reviewed included: identification of the problem was complete and accurate; 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 that the classification, prioritization, focus, and timeliness of CAs 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 included 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 were identified.

.2 Daily Corrective Action Program 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 CR 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 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 through December 31, 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.

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

b. Findings

(1) Failure to Submit LER per 10 CFR 50.73(a)(2)(v)(A) and (D)

Introduction: A Severity Level IV NCV of 10 CFR 50.73(a)(2)(v)(A) and (D) was identified by the inspectors for the failure of the licensee to report an event or condition that could have prevented the fulfillment of safety functions, which are relied upon to shutdown the reactor and maintain it in a shutdown condition, and mitigate the consequences of an accident, respectively. Specifically, examples were identified where high energy line break (HELB) barriers were not appropriately controlled and both divisions of TS-required safety-related equipment, including but not limited to auxiliary feedwater and SI, would not be protected from a HELB event.

Description: During the first quarter of 2010, the inspectors reviewed procedure NP 8.4.16, "PBNP High Energy Line Break Barriers/Vent Paths," Revision 14, and found that the procedure allowed designated penetrations to be out-of-service for 24 consecutive hours and allowed designated doors to be out-of-service for 12 consecutive hours. The inspectors reviewed the guidance provided in NRC Regulatory Issue Summary (RIS) 2001-009, "Control of Hazard Barriers," which indicated that risk must be managed in accordance with 10 CFR 50.65(a)(4) of the maintenance rule and that the TS operability requirements should be evaluated using the appropriate operability guidance.

The inspectors noted that procedure NP 8.4.16 did not provide guidance to perform an operability evaluation for TS SSCs that were impacted when a HELB barrier was removed from service. Additionally, the inspectors did not find any generic licensee guidance relative to control of hazard barriers. Hazard barriers, such as fire barriers, HELB barriers, and flood barriers, had procedures specific to their type. A review of related procedures did not reveal any guidance relative to assessing the operability of TS SSCs.

The inspectors communicated their observations to the licensee relative to RIS 2001-009 and TS operability requirements for various hazard barrier items on several occasions between March 23 and June 8, 2010. During these discussions, the inspectors expressed concern that TS SSCs were not being evaluated for operability when supporting hazard barriers were being removed from service. The inspectors noted that the related operating experience, RIS 2001-009, and RIS 2005-20, "Operability Determinations & Functionality Assessments for Resolution of Degraded or Nonconforming Conditions Adverse to Quality or Safety," warranted these reviews.

On June 11, 2010, the licensee created "Operations Notebook" temporary instruction, "HELB Barrier/Vent Path Temporary Guidance," which clarified HELB barrier breaches that did not require prior approval, an engineering evaluation, or entry into a TS action statement as a result of operability issues. One requirement of this procedure stated that, "Normal ingress and egress through HELB barrier doors. Doors may be held open by hand, but shall NOT be blocked open or held open by some other device."

On June 25, 2010, while performing a plant tour, an inspector observed the licensee placing a wedge under the control room door and questioned the acceptability of the activity. The shift manger and shift technical advisor quoted procedure NP 8.4.16 requirements and provided the inspector a copy of the related pages. Subsequently, the resident inspectors discussed the matter with the shift manager and the shift technical advisor and reviewed the Operations Notebook instruction, "HELB Barrier/Vent Path Temporary Guidance" prohibition about wedging the control room door open. This guidance indicated that NP 8.4.16 was under revision to "eliminate the 12 & 24 hr allowance and require Design Engineering review and approval before a barrier is breached." The work order for the repair of the control room door indicated that the out-of-service time was 36 minutes. Because the guidance prohibited the wedging open of the control room door, this performance deficiency was evaluated as a procedural noncompliance and the violation was documented in NRC Integrated Inspection Report 05000266/2010003; 05000301/2010003. This issue was entered into the licensee's corrective action program as CR1176020.

The inspectors determined that for TS-required systems whose controls interface with the control room, which is designated as a mild environment, operability cannot be assured when a HELB barrier is removed or blocked open, and the control room would be exposed the harsh environment present during a main steam line break or other HELB event. The inspectors determined that the auxiliary feedwater function was applicable to 50.73(a)(2)(v)(A) since it was a system needed to safely shut down the reactor and that the SI function was applicable to 10 CFR 50.73(a)(2)(v)(D) since it was a system needed to mitigate the consequences of an accident and was described in the FSAR as a system needed to mitigate a main steam line break.

The inspectors questioned why the licensee did not report the June 25 event under 10 CFR Part 50.73(a)(2)(v). This report should have been submitted on or before August 24. The licensee stated that since the HELB event did not actually occur they believed that they did not lose the safety function. The inspectors discussed NUREG-1022, “Event Reporting Guidelines 10 CFR 50.72 and 50.73,” Section 3.2.7 with the licensee, which states, “The intent of these criteria is to capture those events where there would have been a failure of a safety system to properly complete a safety function, regardless of whether there was an actual demand.”

On September 3, 2010, the licensee completed the apparent cause evaluation (ACE) for the blocked open control room door that occurred on June 25, 2010. The ACE reviewed how the corrective actions to address inadequate procedure NP 8.4.16, Revision 14, failed to prevent the door from being blocked open again. The ACE also identified that that the control room door maintenance had been previously performed every six weeks and used procedure NP 8.4.16 for HELB barrier control. The inspectors determined that the licensee only had to report one failure for all of the historical examples identified for the inadequate procedure NP 8.4.16, Revisions 0 through 14. However, the failure of the licensee’s implemented corrective actions for the inadequate procedure, identified on June 25 by NRC inspectors, would be a separate reportable failure. The ACE also discussed at least one other subsequent HELB barrier event that should have been reported on or before October 26, 2010. The licensee agreed with the inspectors' observations and entered these issues into the CAP.

<u>Analysis</u>: The inspectors determined that the failure to report the condition in accordance with 10 CFR 50.73(a)(2)(v)(A) and (D) was a performance deficiency. Because violations of 10 CFR 50.73 are considered to be violations that potentially impact the regulatory process, they are dispositioned using the traditional enforcement process instead of the Reactor Oversight Process (ROP) SDP. Because the performance deficiency, a failure to report, was not more than minor and not a finding per Inspection Manual Chapter 0612, Appendix B, “Issue Screening,” a cross-cutting aspect was not assigned to this violation. Per the NRC Enforcement Policy, Section 6.0, “Violation Examples,” a failure to submit a required LER is categorized as a Severity Level IV violation.

<u>Enforcement</u>: Title 10 CFR 50.73(a)(2)(v) requires, in part, that licensees report any event or condition that could have prevented the fulfillment of the safety function of structures or systems that are needed to (A) shutdown the reactor and maintain it in a safe shutdown condition, and (D) mitigate the consequences of an accident. Contrary to this requirement, on August 24, 2010, and October 26, 2010, the licensee failed to report a condition that could have prevented the fulfillment of a safety function. The specific safety functions affected include, but are not limited to, auxiliary feedwater and SI. Because this violation was not repetitive or willful, and was entered into the licensee’s corrective action program (as CR0161620), this violation is being treated as a Severity Level IV NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy (NCV 05000266/2010005-03; 05000301/2010005-03, Failure to Submit LER per 10 CFR 50.73(a)(2)(v)(A) and (D)).

(2) Unresolved Item (URI) for HELB Controls

Introduction: During the semiannual trend review, the inspectors included within the scope of the sample, hazard barrier controls by the licensee. At the conclusion of the inspection period, the inspectors were concerned with the licensee's control of various barriers that were removed or modified for maintenance activities or modifications.

Description: The inspectors were concerned with the control of hazard barriers during the recent auxiliary feedwater modification and at the conclusion of the inspection period, the licensee was gathering information needed to answer the inspectors' questions. The inspectors needed the additional information to assess whether a performance deficiency existed. Specifically, the inspectors were concerned with how various barriers were controlled during the installation of piping and cables from the turbine building to the auxiliary building. Additionally, at the conclusion of the inspection period, the licensee was determining, as the result inadequate HELB controls in procedure NP 8.4.16, "PBNP High Energy Line Break Barriers/Vent Paths," Revision 14, which rooms did not have proper HELB barrier controls, how long the rooms were without proper HELB barriers, and whether some rooms remained a mild environment even with the HELB barriers removed. These issues are being tracked as URI 05000266/2010005-04; 05000301/2010005-04, High Energy Line Break Barrier Controls).

.4 Annual Sample: Review of Operator Workarounds

a. Inspection Scope

The inspectors evaluated the licensee's implementation of the 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 operator workarounds (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 Attachment to this report 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 CAs which 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

No findings were identified.

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

.1 Response to Unplanned or Non-Routine Events

a. Inspection Scope

The inspectors reviewed the plant's response to the following non-routine events:

- unplanned reactor shutdown due to exceeding control rod drive surveillance interval; and
- aborted reactor startup due to control rod drive system failures.

The inspectors reviewed the plant's response to an unplanned reactor shutdown that occurred on December 13 when the licensee exceeded the allowed surveillance interval for control rod testing. After performing a limited scope repair and review of the system, the licensee attempted to restart the reactor on December 15. However, during the restart activities, the startup was aborted when the control rod system experienced multiple failures. Full evaluation of this issue will be completed during closure of the related LERs, which will be issued during the first quarter of 2011. Documents reviewed are listed in the Attachment to this report.

This event follow-up review constituted two samples as defined in IP 71153-05.

b. Findings

No findings were identified.

.2 (Closed) LER 05000266/2010-001-00/01, Engineered Safety Features Steam Line Pressure Dynamics Modules Discovered Outside of Technical Specification Values

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 adequate maintenance procedures for calibrating the ESFAS (Engineered Safety Features Actuation System) Steam Line Pressure dynamic compensation modules. Specifically, since the basis calculation for determining the settings of the lead/lag values for the modules did not address dynamic settings, and the proceduralized tolerances were too restrictive, the calibration instructions were inadequate to ensure the modules' ability to perform in accordance with TS requirements.

Description: On March 3, 2010, with Unit 1 in hot shutdown, the licensee identified that five out of six of the Unit 1 ESFAS Steam Line Pressure channel dynamic compensation modules had as-found lead time constant values below the TS-required value of greater than or equal to 12 seconds. This condition was identified during performance of 1 ICP0 4.001E, "Reactor Protection and Safeguards Analog Racks Steam Pressure Refueling Calibration," under WO 0367035-01. The as-found lead time constant values for the five pressure modules were: 1PM-468A was 11.846 seconds;

1PM-469A was 11.859 seconds; 1PM-482A was 11.914 seconds; 1PM-478A was 11.908 seconds; and 1PM-483A was 11.834 seconds.

The specified safety functions of note for these modules were to ensure the actuation of SI upon a steam line low pressure condition and were credited as an anticipatory primary trip in the steam pipe rupture and steam line break outside containment accident analyses. Additionally, the modules were considered an anticipatory backup trip in the steam line break inside containment accident analysis.

At the time of discovery, the instrumentation was not required to be operable per TSs. However, because the actual time that the instruments drifted into the inoperable range could not be determined with certainty, the entire period since the last calibration (November 10, 2008, to March 1, 2010) was assessed for past operability. As documented in LER 0500266/2010-001-00, an ACE, and a technical assessment for reportability (TAR), the licensee showed through calculation that the modules always remained capable of performing their specified safety functions despite being out-of-tolerance.

The lead/lag dynamic compensation modules monitor changes in steam line pressure and produce a time-dependent variable output, based on a complex equation. The licensee concluded that a combination of factors lead to the inoperability of these modules. First, the basis calculation, PBNP-IC-10, Foxboro 66RC-OLA Lead/Lag Module Drift Calculation, did not address dynamic response settings and was, therefore, determined to be deficient. Additionally, in 2007, the licensee began using a much more accurate method of calibration than what was previously used. Finally, the ACE stated that age degradation contributed to the out-of-tolerance findings.

Through a review of the ACE and discussions with licensee engineering staff, the inspectors concluded that technicians historically compensated for the uncertainty introduced during the calibration process by providing more margin when setting the modules. It was further concluded that this practice likely masked the inherent inadequacies of the basis calculation to address the dynamic settings and the age-related degradation of the components. In 2007, a more accurate method of calibration of the models was employed. This provided the technicians with the ability to set the modules with higher precision and eliminated the need for compensating for the inherent inaccuracies of the previous method. The loss of additional margin introduced through the prior calibration practices resulted in existing calculational deficiencies being revealed.

Since the setpoint values and tolerances within the calibration procedure were a direct output from the basis calculation, the inspectors concluded that the calibration procedure ICP 04.001E was inadequate because its values were derived from the deficient calculation PBNP-IC-10. The inspectors noted that the licensee's ACE documented a number of proposed CAs including, but not limited to, procedure revisions and an engineering change request to revise/supplement the calculation. Additionally, as an interim measure, the licensee has implemented periodic checks to ensure that the setpoints have not drifted out of specification.

Analysis: The inspectors determined that the failure to have maintenance procedures appropriate to the circumstances for calibrating the ESFAS Steam Line Pressure dynamic compensation modules was contrary to 10 CFR 50, Appendix B, Criterion V, and was a performance deficiency.

The finding was determined to be more than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," dated December 24, 2009, because the finding was associated with the Mitigating Systems Cornerstone attribute of equipment performance and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, since the calculational basis for setting the lead/lag values for the modules did not address dynamic settings, the calibration procedure ICP 04.001E was not adequate to ensure the modules would be calibrated to values that ensured the ability to perform in accordance with TS requirements. As a result, five TS-required ESFAS instrumentation modules were rendered inoperable for greater than their allowed outage time.

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, because the inspectors answered "no" to all questions in the column. The licensee was able to provide evidence through a calculation and analysis performed in an evaluation for reportability that the inoperable ESFAS modules remained capable of performing their specified safety functions despite being out-of-tolerance.

The inspectors did not identify a cross-cutting aspect associated with this finding because the basis calculation for calibrating the modules was created in 1995, and had not been revised, thus the performance deficiency for the inadequacy of this calculation was not considered to be representative of present performance, as defined in IMC 0612, dated April 30, 2010.

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, procedures, or drawings of a type appropriate to the circumstances and be accomplished in accordance with these instructions, procedures, or drawings.

Contrary to this, from the issuance of calculation PBNP-IC-10 in 1995, to the present, the licensee failed to prescribe documented instructions, procedures, or drawings of a type appropriate to the circumstances regarding the calibration of the ESFAS Steam Line Pressure dynamic compensation modules. Specifically, the basis calculation did not address dynamic calibration settings and, as a result, multiple TS-required instruments were calibrated in a manner that did not allow them to remain operable during their mode of applicability. Because this violation was of very low safety significance and was entered into the licensee's CAP (as AR01168460), it is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy (NCV 05000266/2010005-05, 05000301/2010005-05, Multiple ESFAS Steam Line Pressure Channel Modules Inoperable Due to Inadequate Calibration Instructions).

.3 (Closed) LER 05000301/2010-001-00, Manual Reactor Trip Following Automatic Turbine Trip Due to Generator Lockout

On June 19, 2010, Unit 2 was at 44 percent power for condenser cleaning. Two sets of condenser steam dump valves had been isolated in preparation for this activity. Shortly after reactor power was lowered to this level, the main generator monitoring circuitry incorrectly sensed a fault on the generator, which resulted in a generator trip and a turbine trip. With half of the steam dumps out-of-service, operators were not able to stabilize reactor power and inserted a manual reactor trip.

The licensee identified that the generator stator ground third harmonic protective relays were set incorrectly from the setpoint calculation. In response to installation of a new main power transformer and a 19-kV (kilovolt) main generator output breaker during fall 2009, the setpoint calculation was revised. However, the revised calculation used an existing methodology that generated setpoints that were not correct for the installed configuration across the full range of power operation. The licensee determined that the setpoint calculation did not receive appropriate level of review based on risk management processes.

Since the setpoint calculation, the generator protection relays (which were installed to protect the turbine generator), and the turbine generator were not safety-related, the inspectors determined that no performance deficiencies or violations of regulatory requirements of safety significance existed. The inspectors had no further concerns in this area.

During the transient on June 19, 2010, the TS P-9 permissive was in effect and that permissive is a function of steam dump capacity. This permissive allows the reactor to remain operating when the turbine trips and the reactor power is less than 50 percent. As discussed in numerous sections of the FSAR, a functioning steam dump system is the basis for the permissive. Following questions by the inspectors, the licensee was reviewing the acceptability of taking steam dumps out-of-service below 50 percent reactor power. This was the subject of URI 05000266/2010003-04; 05000301/2010003-004) which will be discussed further in Section 4OA3.4. Documents reviewed are listed in the Attachment to this report. This LER is closed.

.4 <u>Closed URI 05000266/2010003-04; 05000301/2010003-04, Potential Degradation of Reactor Protection System P-9 Permissive Operability</u>

<u>Introduction</u>: The inspectors identified a finding of very low safety significance and an associated Severity Level IV NCV of 10 CFR 50.59, “Changes, Tests, and Experiments,” for the failure to document an evaluation that provided a basis for the determination that the changes made to procedure OI-38, “Circulating Water System Operation,” did not require a license amendment. Specifically, the licensee failed to provide an evaluation that adequately documented and demonstrated that differences between the procedure changes modifying the operational configuration of the condenser steam dump system (SDS), and operational considerations and design assumptions outlined within the FSAR and the basis of TSs, were acceptable.

<u>Description</u>: On June 19, 2010, the inspector responded to the plant for a Unit 2 unplanned reactor trip. Prior to the trip, Unit 2 was at 44 percent reactor power for condenser cleaning activities. The plant alignment had one circulating water pump secured and the steam dumps to the related condenser bays tagged out-of-service in anticipation of workers entering the related waterboxes for maintenance. At this power level, the main generator monitoring circuitry incorrectly sensed a fault on the generator, which resulted in a generator trip and a related turbine trip. As a result of the turbine trip, reactor controls sensed a power mismatch and automatically inserted control rods to control reactor coolant temperature. However, with half of the steam dumps

out-of-service, operators were unable to stabilize reactor power and inserted a manual reactor trip.

The inspectors reviewed operator and equipment performance during the transient and noted that the P-9 permissive was in effect at the time of the transient. The P-9 permissive is a TS reactor protection system (RPS) device that bypasses the “reactor trip on turbine trip” feature of the RPS when the reactor power is less than 50 percent (i.e., P-9 prevents a reactor trip on turbine trip below 50 percent reactor power). This bypass is allowed because the combined capabilities of the control rod drive system and SDS can automatically (i.e., without operator action) accommodate a 50 percent load reject without sustaining a reactor trip. This is accomplished because the SDS can accommodate 40 percent steam load and the control rod system will compensate for an additional 10 percent power.

The licensee restarted the unit on June 20, 2010, and reactor power remained below 50 percent for several days to facilitate condenser water-box cleaning. During this time, the licensee continued to operate with half of the steam dump valves isolated. On June 21, the inspectors questioned the licensee about operation of the unit below 50 percent reactor power with diminished steam dump capacity and inquired about the impact on the operability of the P-9 and turbine trip functions of the RPS. The inspectors discussed the related TS basis and questioned the licensee about any evaluation of P-9 and the automatic reactor trip function with half of the steam dumps isolated.

Procedure EN-AA-203-1001, “Operability Determination/Functionality Assessments,” Revision 2, Step 3.1.1, under “Responsibilities - Plant Personnel,” required that plant personnel, “Initiate a Corrective Action Program (CAP) Action Request (AR) or Condition Report (CR) when a potential problem with a SSC [structure, system, or component] is identified that requires resolution or corrective action implementation.” A CR was not initiated nor a prompt operability evaluation performed when the inspectors brought the disparity between the current licensing basis and the operating condition to the attention of the licensee.

The inspectors reviewed the licensee’s TSs and FSAR and found multiple references that indicated the condenser SDS and the anticipatory reactor trip on a turbine trip had been included as a design input to transient and accident response. Specifically, the inspectors found that the turbine trip feature of the RPS was provided to back up the primary tripping features of RPS for specific accident conditions and mechanical failures; that the design requirements for the turbine trip feature of RPS was verified by analysis; and that the ability to bypass the turbine trip function of RPS using P-9 presumed that a load rejection can be accommodated by the SDS. The inspectors determined that SDS capacity was an input assumption associated with both of these RPS features; and that the licensee degraded the capacity of the SDS without performing an evaluation to assess the impact of the degraded capacity on the plant design or TS requirements.

The licensee evaluated the inspectors' observations in ACE01185112, and identified several contributing causes, including: the operators were influenced to accept the configuration because the condenser steam dumps were not in TSs, not safety-related, and presumed that they needed to be isolated to provide worker protection; and the operators placed a reliance on the quality of the procedure governing the configuration of the condenser steam dumps during waterbox cleaning activities. The licensee determined the cause of the failure to evaluate the observed differences between plant operating configuration and the current licensing basis was that, "Changes made in 2001 to OI-38 were insufficiently evaluated with regards to the potential impacts on plant transients, and therefore developed into a legacy accepted practice for configuration control of condenser steam dumps for waterbox cleaning. [i.e., an inadequate 10 CFR 50.59 evaluation was performed]." Subsequently, the licensee also evaluated the impact of the configuration against the assumptions in the FSAR and for the exact power level, plant configuration, and time in core life, and determined that the identified operational condition was within the limits of the related design assumptions during this specific instance.

Analysis: The inspectors determined that the failure to follow EN-AA-203-1001 and perform an operability evaluation when a concern relating to a TS item (i.e., P-9) was identified was a performance deficiency warranting further review. The inspectors determined that the issue was more than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," dated December 24, 2009, because it was associated with the Mitigating Systems Cornerstone attribute of equipment performance and adversely affected the cornerstone objective to ensure that availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, by failing to initiate a CR, the licensee did not assess the relationship between the SDS and related RPS device functions.

Violations of 10 CFR 50.59 are dispositioned using the traditional enforcement process instead of the SDP because they are considered to be violations that potentially impede or impact the regulatory process. However, if possible, the underlying technical issue is evaluated under the SDP to determine the severity of the violation. In this case, the inspectors determined that the underlying 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," Tables 3b and 4a, for the Mitigating Systems Cornerstone, dated January 10, 2008, and answered "no" to all of the questions in the tables. Therefore, the issue screened as having very low safety significance (Green). Additionally, the inspectors with the assistance of the Senior Reactor Analyst determined that required mitigating equipment for this event was the feed and condensate system and it was available throughout the duration of the unanalyzed condition.

The inspectors determined that the underlying finding had a cross-cutting aspect in the problem identification and resolution area because the licensee failed to thoroughly evaluate questions regarding differences between the plant operational configuration and assumptions in the current licensing basis (CLB) when they did not complete a prompt operability evaluation to assess noted operational disparities (P.1(c)). Specifically, had a CR been initiated and the CLB evaluated relative to the SDS, the licensee would have recognized the interrelationship between the SDS and P-9 in the TSs, and the resultant evaluation would have assessed the degraded nature of the SDS.

Enforcement: Title 10 CFR 50.59, "Changes, Tests, and Experiments," Section (d)(1) requires, in part, the licensee to maintain records of changes in procedures made pursuant 10 CFR 50.59(c) and that these records include a written evaluation which provides the bases for the determination that the change, test, or experiment does not require a license amendment.

Contrary to this, the licensee changed a procedure but did not maintain a record of the change that included a written evaluation. Specifically, the licensee failed to provide an evaluation that adequately documented that differences between the procedure changes modifying the operational configuration of the condenser SDS and operational considerations and design assumptions outlined in the FSAR and the basis of TSs were acceptable when they revised procedure OI-38, "Circulating Water System Operation," in 2001. In accordance with the NRC Enforcement Policy, this violation was classified as a Severity Level IV violation because the underlying technical issue was of very low risk significance. Because this violation was of a very low safety significance, was not repetitive or willful, and was entered into the licensee's CAP, it is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy (NCV 05000266/2010005-06, 05000301/2010005-06, Failure to Document a 10 CFR 50.59 Evaluation For Changes Made to Procedure OI-38, Circulating Water System Operation).

The finding is evaluated separately from the traditional enforcement violation and, therefore, the finding is being assigned a separate tracking number (FIN 05000266/2010005-07; 05000301/2010005-07, Failure to Document a 10 CFR 50.59 Evaluation For Changes Made to Procedure OI-38, Circulating Water System Operation). As part of its corrective action, the licensee entered the issue into its CAP (as CR01394200) and revised OI-38 to remove the original change to the operational configuration of the SDS.

.5 <u>(Closed) LER 05000301/2010-002-00, Manual Reactor Trip Due to Failure of Feedwater Regulating Valve Positioner</u>

On July 9, 2010, operators initiated a manual reactor trip of Unit 2 as a result of a failure of the diaphragm in the feedwater regulating valve positioner A. This issue was previously reviewed and documented in Inspection Report 05000266/2010004; 05000301/2010004.

The licensee post-event inspection of the positioner identified a tear in the diaphragm. The licensee concluded that the tear originated in a manufacturing defect. Since the valve was rebuilt in 2005, the valve was diagnostically tested four times and did not show any anomalies. The related failure analysis report stated that once the tear began, full failure (immediate) would be expected due to the stress concentrations at the tear edges. This was consistent with past tests and the failure event on July 9, 2010.

Based on a review of the licensee's root cause analysis of the failure, the inspectors determined that no performance deficiencies or violations of regulatory requirements of safety significance existed. The inspectors had no further concerns in this area. Documents reviewed are listed in the Attachment to this report. This LER is closed.

.6 <u>(Closed) LER 05000266/2010-002-00, Manual Reactor Trip Due to Lowering Condenser Vacuum</u>

On July 26, 2010, licensed operators initiated a manual reactor trip of Unit 1 from approximately 19 percent power. The generator breaker was just opened and the secondary side steam load was transferred to the condenser steam dumps when condenser vacuum lowered unexpectedly. The reactor was manually tripped in accordance with plant procedures due to an uncontrolled lowering of main condenser vacuum and prior to an automatic trip of the reactor. All systems functioned as designed following the reactor trip. Documents reviewed are listed in the Attachment to this report. This LER is closed.

This event follow-up review constituted one sample as defined in IP 71153-05.

a. Findings

(1) Failure to Follow Power Operation to Hot Standby Procedure Results in Reactor Trip

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 when an auxiliary operator (AO) failed to correctly perform a procedure step, which resulted in the turbine crossover steam dump (TCSD) valves remaining open.

Description: On July 26, 2010, operators commenced a planned shutdown of Unit 1 to repair an identified hydrogen gas leak on the main generator. The shutdown started at 12:42 p.m. at a load reduction of 15 percent per hour, with plant operations controlled by procedure OP-3A, "Plant Shutdown to Hot Standby." The oncoming operations crew attended "just-in-time" training for taking the unit offline; however, the AOs assigned to the field activities were not part of that training and were briefed separately for the performance of field activities. Following shift turnover at 3:00 p.m., the senior reactor operator (SRO) directed an AO to perform step 5.11.7 of procedure OP-3A. The step prescribed that the AO ensured the Unit 1 TCSD valves were closed and that the control switches were placed to stop at the local control panel in the field.

The briefing that the SRO provided to the AO only covered the performance of the step by a quick review of the field copy of the procedure due to the perceived simplicity of the prescribed action. No discussion occurred on the use of a peer checker or an independent verifier to verify the valves were closed or what actions should be taken if the TCSD valves were found in the open position. To close the TCSD valves, two AOs were needed with radio communications, with one AO at the local panel and the second AO at the valve locally, to verify the valves torqued closed.

The AO arrived at the local control panel, glanced at the indicating lights and errantly perceived that the TCSD valves were closed, when in actuality the red (open) lights were lit for each valve and the corresponding position meters indicated open. Because he believed the TCSD valves were closed, the AO performed the final portion of step 5.11.7 taking the control switch to stop, which disabled the automatic function of the TCSD valves. The AO called the control room and notified a reactor operator that the valves were closed and that the control switch was in stop. The control room operator who received the call proceeded to verify the valve position behind the control panels; however, he was interrupted by a control room alarm and never verified the status of the TCSD valves. No direction at the pre-job brief was given to a reactor operator to verify the status of the valves in the control room because the reactor operator was not involved in the pre-job brief. Control room personnel then proceeded with the reactor shutdown per procedure OP-3A.

At 7:52 p.m., the Unit 1 main generator main breaker was opened in accordance with procedure OP-3A. After the turbine generator was taken offline, the lowering of the crossover steam pressure allowed air to leak past the TCSD valve seats, through the open TCSD isolation valves into the Unit 1 main condenser. This created the lowering vacuum condition in the condenser that required the reactor operator to trip the reactor at 8:01 p.m. Operations personnel performed emergency operating procedure EOP-0 and all plant equipment responded as designed to the reactor trip. The operations crew then discovered that the lowering condenser vacuum condition was caused by the open TCSD valves. Subsequently, the operating crew made all the required notifications to the NRC in a timely manner.

Analysis: The inspectors determined that the licensee's failure to implement procedure steps as prescribed was contrary to the requirements of 10 CFR Part 50, Appendix B, Criterion V, and was a performance deficiency warranting a significance evaluation.

The finding was determined to be more than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," dated December 24, 2009, because it was associated with the Initiating Events Cornerstone attribute of human performance and adversely 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, the failure to follow the procedure resulted in a reactor trip.

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," Tables 3b and 4a for the Initiating Events Cornerstone, dated January 10, 2008. The inspectors answered "no" to the Initiating Events Cornerstone Transient Initiator question and screened the finding as having very low significance (Green).

The finding has a cross-cutting aspect in the area of human performance, work practices, because operations personnel did not utilize human performance error prevention techniques. Specifically, operations personnel failed to follow standards for pre-job briefs, verification and validation, and self-checks (H.4(a)).

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

Contrary to this, on July 26, 2010, during the performance of procedure OP-3A, "Power Operation to Hot Standby – Unit 1," an activity affecting quality, the AO failed to perform step 5.11.7. Specifically, the step prescribed that the AO ensure that the Unit 1 TCSD valves were closed and that the control switches were placed to stop. However, the AO never closed the TCSD valves and placed the control switch to stop. Consequently, an air flowpath was created that resulted in a loss of condenser vacuum, which forced the licensed operators to trip the Unit 1 reactor per plant procedures. Because this violation was of very low safety significance and because it was entered into the licensee's CAP (as AR01177992), this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy (NCV 05000266/2010005-08, Failure to Follow Power Operation to Hot Standby Procedure).

The licensee performed a root cause evaluation that determined the root cause was improper application and adherence to human performance tool standards, which resulted in the incorrect status of the TCSD valves. The licensee subsequently implemented several corrective actions that included changes to the operators continuing training program to incorporate human performance related job performance measures.

4OA6 Management Meetings

.1 Exit Meeting Summary

On January 4, 2011, 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 confirmed that none of the potential report input discussed was considered proprietary.

.2 Interim Exit Meetings

Interim exits were conducted for:

- The annual review of EAL and EP changes with the licensee's Emergency Preparedness Manager, Mr. J. Schleif, via telephone on December 8, 2010.
- Occupational Radiation Safety radiation monitoring instrumentation program inspection with Mr. L. Meyer and others on October 29, 2010.
- The licensed operator requalification training program biennial written examination and the annual operating test results with Mr. L. Germann, Operations Continuing Training Instructor, on November 3, 2010.

The inspectors confirmed that none of the potential report input discussed was considered proprietary. Proprietary material received during the inspection was returned to the licensee.

4OA7 Licensee-Identified Violations

The following violation of very low significance (Green) was identified by the licensee and is a violation of NRC requirements which meets the criteria of the NRC Enforcement Policy for being dispositioned as an NCV.

- As documented in LER 05000266-2010-001-01, a violation of TS 3.3.2 for Unit 1 was identified by the licensee during surveillance testing on March 3, 2010. Specifically, five of the six ESFAS steam line pressure dynamic compensation modules were found to have lead time constant values below the TS allowable value required for operability; however, since the licensee's CAP showed that the modules remained capable of performing their specified safety functions, the finding screened as Green in accordance with the SDP. See Section 4OA3.2 of this report for additional information regarding this event and the corrective actions taken.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

J. Schleif, Emergency Preparedness Manager
L. Meyer, Site Vice-President
D. Craine, Radiation Protection Manager
G. LeClair, Radiation Protection Supervisor

Nuclear Regulatory Commission

M. Kunowski, Chief, Reactor Projects Branch 5

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000266/2010005-01; 05000301/2010005-01	NCV	Inadequate Safety System Venting Procedure Void Assessment Requirements (Section 1R22.1.(1))
05000266/2010005-02; 05000301/2010005-02	NCV	Failure to Perform Ultrasonic Assessment of Safety System Voids as Required by Procedure (Section 1R22.1.(2))
05000266/2010005-03; 05000301/2010005-03	NCV	Failure to Submit LER per 10 CFR 50.73(a)(2)(v)(A) and (D). (Section 4OA2)
05000266/2010005-04; 05000301/2010005-04	URI	High Energy Line Break Barrier Controls (Section 4OA2)
05000266/2010005-05; 05000301/2010005-05	NCV	Multiple ESFAS Steam Line Pressure Channel Modules Inoperable Due to Inadequate Calibration Instructions (Section 4OA3.2)
05000266/2010005-06; 05000301/2010005-06	NCV	Failure to Document a 10 CFR 50.59 Evaluation For Changes Made to Procedure OI-38, Circulating Water System Operation (Section 4OA3.4)
05000266/2010005-07; 05000301/2010005-07	FIN	Failure to Document a 10 CFR 50.59 Evaluation For Changes Made to Procedure OI-38, Circulating Water System Operation (Section 4OA3.4)
05000266/2010005-08	NCV	Failure to Follow Power Operation to Hot Standby Procedure (Section 4OA3.6(1))

Closed

05000266/2010005-01; 05000301/2010005-01	NCV	Inadequate Safety System Venting Procedure Void Assessment Requirements (Section 1R22.1.(1))
05000266/2010005-02; 05000301/2010005-02	NCV	Failure to Perform Ultrasonic Assessment of Safety System Voids as Required by Procedure (Section 1R22.1.(2))
05000266/2010005-03; 05000301/2010005-03	NCV	Failure to Submit LER per 10 CFR 50.73(a)(2)(v)(A) and (D) (Section 4OA2)

05000266/2010-001-00; 05000266/2010-001-01	LER	Engineered Safety Features Steam Line Pressure Dynamics Modules Discovered Outside of Technical Specification Values (Section 4OA3.2)
05000266/2010005-05; 05000301/2010005-05	NCV	Multiple ESFAS Steam Line Pressure Channel Modules Inoperable Due to Inadequate Calibration Instructions (Section 4OA3.2)
05000301/2010-001-00	LER	Manual Reactor Trip Following Automatic Turbine Trip Due to Generator Lockout (Section 4OA3.3)
05000266/2010003-04; 05000301/2010003-04	URI	Potential Degradation of Reactor Protection System P-9 Permissive Operability (Section 4OA3.4)
05000266/2010005-06; 05000301/2010005-06	NCV	Failure to Document a 10 CFR 50.59 Evaluation For Changes Made to Procedure OI-38, Circulating Water System Operation (Section 4OA3.4)
05000266/2010005-07; 05000301/2010005-07	FIN	Failure to Document a 10 CFR 50.59 Evaluation For Changes Made to Procedure OI-38, Circulating Water System Operation (Section 4OA3.4)
05000301/2010-002-00	LER	Manual Reactor Trip Due to Failure of Feedwater Regulating Valve Positioner (Section 4OA3.5)
05000266/2010-002-00	LER	Manual Reactor Trip Due to Lowering Condenser Vacuum (Section 4OA3.6)
05000266/2010005-08	NCV	Failure to Follow Power Operation to Hot Standby Procedure (Section 4OA3.6(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 inspector reviewed the documents in their entirety, but rather that selected sections or portions of the documents were evaluated as part of the overall inspection effort. Inclusion of a document on this list does not imply NRC acceptance of the document or any part of it, unless this is stated in the body of the inspection report.

1R01 Adverse Weather Protection

- CAP01181584; Unit 2 MISIV Cabinets Had Heat Trace Tagged Over Winter; September 28, 2010
- CAP01183694; Unit 2 MSIV Solenoid Cabinet Heating; November 2, 2010
- Lab Number V5000311; Herguth Laboratories Certificate Of Analysis; Sample ID: G03, Glycol Cooling Water; March 17, 2010
- Lab Number V5001047; Herguth Laboratories Certificate Of Analysis; Sample ID: G03, Glycol Cooling Water; June 10, 2010
- Lab Number V5001725; Herguth Laboratories Certificate Of Analysis; Sample ID: G03, Glycol Cooling Water; August 18, 2010
- NP 2.1.9; Seasonal Readiness; Revision 1
- PC 49 Part 1; Turbine Hall Ventilation Unit 1; Performed September 7, 2010
- PC 49 Part 2; Turbine Hall Ventilation Unit 2; Performed September 16, 2010
- PC 49 Part 3; Auxiliary Building Ventilation; Performed October 12, 2010
- PC 49 Part 4; Auxiliary Building Miscellaneous And Facades; Performed October 4, 2010
- PC 49 Part 5; Cold Weather Checklist: Outside Areas And Miscellaneous; Revision 25
- PC 49 Part 5; Cold Weather Checklist: Outside Areas And Miscellaneous; Performed September 23, 2010
- PC 49; Cold Weather Preparations; Revision 7
- Site Certification Letter For Cold Weather Readiness Period 2010 (CWRP) Per OP-AA-102-1002 Seasonal Readiness, Attachment B; September 23, 2010
- WO374032; Winter Readiness, HX-077 BAE Removed Relief Valves U2 Façade; October 29, 2010

1R04 Equipment Alignment

- CL 13E Part 1; Auxiliary Feedwater Valve Lineup Turbine-Driven, Unit 2; Revision 21
- Microfilm No. 084854; P&ID Main and Reheat Steam System, Unit 2; June 12, 1977
- Microfilm No. 275460; P&ID Auxiliary Feedwater System, Unit 1&2; February 22, 1993
- Microfilm No. 275463; P&ID Service Water, Unit 1; February 2, 1993

1R05 Fire Protection

- DBD-16; Emergency Diesel Generator System; Revision 14
- Drawing 4002-2; Diesel Generator Building Fire Alarm System Device Locations – Ground Floor; Revision 4
- Drawing PB31EFPL40300102; Electrical Layout Fire Detection System Diesel Generator Building 1st Floor (EL.28'.0"); February 16, 1995
- Drawing PB31MVDL00000106; Diesel Generator Building Air Flow Diagram HVAC Systems; December 12, 2007
- Drawing PBC-218 SH.19; Fire Protection For Diesel Generator Building; Revision 4
- Duke Engineering And Services Fire Area Analysis Summary Report For: Fire Area A71, Combined DG Building, Train B Areas; August 8, 2005

- Fire And Smoke Detection System Index, Diesel Generator Building Room 106; July 12, 1994
- NFPA 72E; Standard on Automatic Fire Detectors; 1990 Edition
- PBNP WPF; PBNP Diesel Project Design Submittal; Revision 0
- SER 93-025-19; 10 CFR 50 Report For G03/04 1993 Modification
- Sheet No. 05; Fire Detector Location Sheet
- Sheet No. 06; Fire Detector Location Sheet
- Sheet No. 15; Fire Detector Location Sheet
- Sheet No. 16; Fire Detector Location Sheet
- TRHB 11.16; Secondary Systems Descriptions: Heating And Ventilation System; Revision 12

1R11 Licensed Operator Requalification Program

- Results Of Biennial Written Examination And Annual Operating Test; November 3, 2010

1R12 Maintenance Rule Implementation

- Procedure Record for No. IT 09A, Cold Start Of Turbine-Driven Auxiliary Feed Pump And Valve Test (Quarterly) Unit 2; November 15, 2010
- IT 09A; Cold Start Of Turbine-Driven Auxiliary Feed Pump And Valve Test (Quarterly) Unit 2; Revision 51
- Maintenance Rule Unavailability Data Sheet; Auxiliary Feedwater System Unit 1; Data Between October 1, 2010 and November 1, 2010
- AR01173557; 2P-29-T Casing Leak Identified During IT-09A Initial Start; May 18, 2010
- AR01177899; 2P-029 TDAFP Train Exceeds 100% Maintenance Rule Threshold; July 26, 2010
- Maintenance Rule Unavailability Data Sheet; Auxiliary Feedwater System Unit 1; Data Between October 1, 2008 and October 1, 2010
- Maintenance Rule (a)(1) System Action Plan Checklist And Approval For Auxiliary Feedwater System; July 1, 2010
- Performance Criteria Assessments for Auxiliary Feedwater System Since October 1, 2008; November 29, 2010
- NP 7.7.4; Scope And Risk Significant Determination For The Maintenance Rule; Revision 17
- NP 7.7.5; Maintenance Rule Monitoring; Revision 21
- AR01115748; 2P-29 Moisture In Oil Concern; November 1, 2007
- AR01185466; NRC Question on MR Unavailability; December 2, 2010
- SEM 1.5; Maintenance Rule Guideline; Revision 3
- AM 3-4; Implementation Of The Maintenance Rule At PBNP; Revision 7
- AR01185455; Maintenance Rule NRC Resident Inspection; December 2, 2010

1R15 Operability Evaluations

2010 ASME Boiler And Pressure Vessel Code; Rules For Construction Of Nuclear Facility Components; Division 1 – Subsection NB, Class 1 Components
- AR01182566; 2HX-37B Heat Exchanger Cracked While Torqueing; October 13, 2010
- AR01183533; Containment Spray Pump Water Cooler (CCW) Shell Rating; October 29, 2010
- AR01184104; NRC Question On Past Operability Requirements; November 9, 2010
- ASME B31.1-2001; Table A-5, Cast Iron; October 14, 2008
Calculation N-94-059; CCW, HX-012A-D, Service Water Flow Verses Temperature Requirement; Revision 3
- CAP 01182921; 2RH-742 RHR Return To RWST Has Potential Internal Binding; October 19, 2010

- CE/AR01137377; 1HX-37A Fouling; October 27, 2008
  Drawing Microfilm No. 275029; ISI Classification Diagram Safety Injection System; Revision 14
- Drawing S1093 (526SVC10); 8X6C-10 Heliflow; Revision 0
- EN-AA-203-1001-F01; POD For: CR1182566; 2HX-37B Heat Exchanger Cracked While Torqueing; October 13, 2010
- EN-AA-203-1001-F01; Prompt Operability Determination (POD) For: CR1183533, Spray Pump Seal Coolers Not Rated For CC System Pressure; October 29, 2010
- EN-AA-203-1001-F03; Technical Assessment For Reportability (Tar) For: CR01182566, 2HX-37B Heat Exchanger Cracked While Torquing; Revision 0
  FSAR Section 14.2.5; Rupture Of A Steam Pipe; USFSAR 2009
  FSAR Section 14.3.4; Containment Integrity Evaluation; USFSAR 2009
- Microfilm No. 018975; P&ID Safety Injection System Unit 2; September 22, 2009
- Microfilm No. 018977; P&ID Auxiliary Coolant System Unit 2; October 28, 2009
- NP 7.4.4; ASME OM Code Pump And Valve Inservice Testing; Revision 6
- WR00045552; 2RH-742 Internal Binding (Potential); October 25, 2010

1R18 Plant Modifications

- Calculation Signature Sheet for Calculation No. 2010-10071; Special Calculation For Evaluating Upstream Flow Restrictions For Unit 2 SI Accumulator Relief Valves Temporary Modification; Revision 0
- DBD-11; Safety Injection And Containment Spray System; Revision 17
- EC16295; Tmod For Temporary Relief Valves On Unit 2 Accumulators, T-34; Revision 0
- EN-AA-212-F01; TMod – EC 16295; September 22, 2010
- FSAR Section 6.2; Safety Injection System; FSAR 2009
- PBF-1515c; 10 CFR 50.59/72.48 Screening for: EC 16295; Tmod For Temporary Relief Valves On Unit 2 Accumulators, T-34; October 1, 2010
- Process EN-AA-200; Design Review Board Endorsement For: EC 16295; September 30, 2010
- QF-0506; Modification Classification for: EC 16295, Tmod For Temporary Relief Valves On Unit 2 Accumulators, T-34; September 22, 2010
- QF-0507; Modification Package Index for: EC 16295, Tmod For Temporary Relief Valves On Unit 2 Accumulators, T-34
- QF-0515B; Design input Checklist for: EC 16295
- QF-0526; Design Verification Assignment for: EC 16295, Tmod For Temporary Relief Valves On Unit 2 Accumulators, T-34; September 23, 2010
- QF-0527; EC 16295, Design Review Checklist: Tmod For Temporary Relief Valves On Unit 2 Accumulators, T-34
- QF-0540; Temporary Modification Control Form for: EC 16295, 2T-034A And B, Safety Injection Accumulator, Alternate Relieve Valves
- QF-0541; EC 16295, Tmod For Temporary Relief Valves On Unit 2 Accumulators, T-34; September 28, 2010
- QF-0541; Temporary Modification Extension for: EC 16295, Tmod For Temporary Relief Valves On Unit 2 Accumulators, T-34; September 22, 2010
- QF-0546; Design Interface Agreement (DIA) For: EC 16295, Tmod For Temporary Relief Valves On Unit 2 Accumulators, T-34; September 19, 2010
- QF-0547; Special Calculation For Evaluating Upstream Flow Restrictions For Unit 2 SI Accumulators Relief Valves Temporary Modification; 2010-10071; September28, 2010
- SCR 2010-0198; 10 CFR 50.59/72.48 Screening; Tmod For Temporary Relief Valves On Unit 2 Accumulators, T-34 A&B

- TMOD (EC) 16295; Tmod Extension for: Tmod For Temporary Relief Valves On Unit 2 Accumulators, T-34; September 22, 2010
- WO Package 00394909; 2T-034A, Install Temporary Modification EC 16295; October 6, 2010
- WO Package 00394919; 2T-034B, Install Temporary Modification EC 16295; October 5, 2010

1R19 Post-Maintenance Testing

- 1X01 Monitoring Plan; AR1182582, X-01 Main Transformer Unit 1; Revision 0
- AR01184382; G-04 Main Oil Filter Leak; November 13, 2010
- AR01185133; TDR G04 Engine Cool Down Timer Relay O.O.S. As Found Reading; November 29, 2010
- AR01185153; Orings Found Damaged in G-04 Thermostatic Valve; November 29, 2010
- AR01185455; Maintenance Rule NRC Resident Inspection; December 2, 2010
- AR01185466; NRC Question on MR Unavailability; December 2, 2010
- Calculation Signature Sheet for Calculation No. 2010-10071; Special Calculation For Evaluating Upstream Flow Restrictions For Unit 2 SI Accumulator Relief Valves Temporary Modification; Revision 0
- CAP01184377; G-04 F-178B Fuel Oil Filter Gasket Leak During Restoration; November 18, 2010
- Causal Evaluation; 1X01 A Phase Isolated Phase Buswork
- DBD-11; Safety Injection And Containment Spray System; Revision 17
- EC16295; Tmod For Temporary Relief Valves On Unit 2 Accumulators, T-34; Revision 0
- EN-AA-212-F01; TMod – EC 16295; September 22, 2010
- FPL-1; Quality Assurance Topical Report; Revision 8
- FSAR Section 6.2; Safety Injection System; FSAR 2009
- NP 1.2.3; Temporary Procedure Changes; Revision 24
- Operational Decision Making; AR01182582, 1 X-01A Elevated Bus Duct Support Temperatures
- PBF-1515c; 10 CFR 50.59/72.48 Screening for: EC 16295; Tmod For Temporary Relief Valves On Unit 2 Accumulators, T-34; October 1, 2010
- PCR1184234 for RMP 9043-43; Emergency Diesel Generator Mechanical Inspection; November 11, 2010
- PCR1184407 for RMP 9043-47A; Emergency Diesel Generator G-04 Post-Maintenance Run And Testing; November 14, 2010
- Procedure Record for No. IT 09A, Cold Start Of Turbine-Driven Auxiliary Feed Pump And Valve Test (Quarterly) Unit 2; November 15, 2010
- Procedure Record For RMP 9043-47A; Emergency Diesel Generator G-04 Post-Maintenance Run; November 13, 2010
- Process EN-AA-200; Design Review Board Endorsement For: EC 16295; September 30, 2010
- QF-0506; Modification Classification for: EC 16295, Tmod For Temporary Relief Valves On Unit 2 Accumulators, T-34; September 22, 2010
- QF-0507; Modification Package Index for: EC 16295, Tmod For Temporary Relief Valves On Unit 2 Accumulators, T-34
- QF-0515B; Design input Checklist for: EC 16295
- QF-0526; Design Verification Assignment for: EC 16295, Tmod For Temporary Relief Valves On Unit 2 Accumulators, T-34; September 23, 2010
- QF-0527; EC 16295, Design Review Checklist: Tmod For Temporary Relief Valves On Unit 2 Accumulators, T-34
- QF-0540; Temporary Modification Control Form for: EC 16295, 2T-034A And B, Safety Injection Accumulator, Alternate Relieve Valves

- QF-0541; EC 16295, Tmod For Temporary Relief Valves On Unit 2 Accumulators, T-34; September 28, 2010
- QF-0541; Temporary Modification Extension for: EC 16295, Tmod For Temporary Relief Valves On Unit 2 Accumulators, T-34; September 22, 2010
- QF-0546; Design Interface Agreement (DIA) For: EC 16295, Tmod For Temporary Relief Valves On Unit 2 Accumulators, T-34; September 19, 2010
- QF-0547; Special Calculation For Evaluating Upstream Flow Restrictions For Unit 2 SI Accumulators Relief Valves Temporary Modification; 2010-10071; September 28, 2010
- RMP 9043-27A; Emergency Diesel Generator G-02 Post-Maintenance Run and Testing; Revision 5
- RMP 9043-37A; Emergency Diesel Generator G-03 Post-Maintenance Run and Testing; Revision 3
- RMP 9043-41; Emergency Diesel Generator G-04 2 Year Electrical Inspection; Revision 12
- RMP 9043-47; Emergency Diesel Generator G-04 Pre-Maintenance Run and Testing; Revision 10
- RMP 9387; AC Induction Motor MCE Testing Procedure; Completed June 16, 2010
- SCR 2010-0198; 10 CFR 50.59/72.48 Screening; Tmod For Temporary Relief Valves On Unit 2 Accumulators, T-34 A&B
- Technical Assessment For Reportability (TAR) For CR01183694; November 30, 2010
- TMOD (EC) 16295; Tmod Extension for: Tmod For Temporary Relief Valves On Unit 2 Accumulators, T-34; September 22, 2010
- TRM 3.8.3; Standby Emergency Power Source Inspections; Revision 1
- Troubleshooting Process Log; AR1182582, 1X-01A/B Iso-Phase Bus Hot Spots; November 13, 2010
- WO Package 00309542-01; 1-X01-A, Doble Insulation Test; March 2, 2010
- WO Package 00333512-01; P-032D-M E-Max Analyze Motor (2B52-27B/2b-04); October 30, 2009
- WO Package 00366513-01; P-032D-M MCE Analyze Motor (2B52-27B/2B-04) With RIC; December 8, 2009
- WO Package 00367896; Replace Relief Valve – Ad Program Unit 2; October 18, 2010
- WO Package 00371083-01; P-032D-M Service Water Pump Motor, Noisy Motor Bearing; March 30, 2009
- WO Package 00373189-01; P-032D-M Inspect And Clean Motor Ventilation Louvers; December 4, 2009
- WO Package 00379001-01; P-032D-M Perform Motor Swamp During Pump Work; December 4, 2009
- WO Package 00389273; Sample And Change Oil As Required Unit 2; November 15, 2010
- WO Package 00389295; Oil Sample And Change Unit 2; October 28, 2010
- WO Package 00390208; Sample And Change Oil As Required Unit 2; October 29, 2010
- WO Package 00390888-01; P-032D-M Seal Conduit Box To Motor Joint; June 24, 2010
- WO Package 00391378-08; Perform Implementation of Modification EC13824; October 18, 2010
- WO Package 00391378-22; Perform Implementation of Modification EC13824; October 18, 2010
- WO Package 00394909; 2T-034A, Install Temporary Modification EC 16295; October 6, 2010
- WO Package 00394919; 2T-034B, Install Temporary Modification EC 16295; October 5, 2010
- WO Package 00395264; Adjust Pump Packing Unit 2; October 27, 2010
- WO Package 395517; 1X-01-A, Ground Hot Spot On Bus Duct Support Structure; October 31, 2010

1R20 Refueling and Other Outage Activities

- AR01175650; Unit 2 Auto Turbine Trip And Manual Reactor Trip; June 19, 2010
- AR01175719; Unit 2 Condenser Steam Dumps In "Pressure Control" Mode; June 21, 2010
- AR01176098; Unit 2 Condenser Steam Dumps In "Pressure Control" Mode; June 28, 2010
- AR01176472; TS Function Of P-9 Interlock And Basis Needs Reconciliation; July 2, 2010
- AR01178684; 2Q10 NRC URI – P-9 Interlock Permissive Operability; August 7, 2010
- AR01185922; Operational Decision Matrix: Unit 2 Rod Control
- AR01185922; U2 Rod Control Urgent Alarm And Non-Urgent Alarm Came In; December 10, 2010
- AR01185922; Unit 2 Rod Control Operational Decision Matrix; December 14, 2010
- AR01185922; US Rod Control Urgent Alarm And Non-Urgent Alarm; December 10, 2010
- AR01778563; Inappropriate Direction In OI-38 (CW System Operation); August 5, 2010
- CAP01185922; Final Refute Matrix; December 14, 2010
- CL 2F; Mode 2 To Mode 1 Checklist; Revision 17
- Determination For The Use Of Not Applicable (NA) For TS-6, Rod Exercise Test Unit 2; December 12, 2010
- EN No. 46482; Event Notification Worksheet; December 15, 2010
- FAR No. 1; Failure Investigation Process Field Action Request (FAR): Several Rod Groups Dropped During U2 Startup On 12/15/10; December 15, 2010
- ICP 06.093; Rod Control System Troubleshooting; December 15, 2010
- NP 5.3.3; Incident Investigation And Post-Trip Review, Personnel Statements; December 15, 2010
- OP 1B; Reactor Startup; December 21, 2010
- OP 1B; Reactor Startup; Revision 61
- OP 1C; Startup To Power Operation Unit 2; Revision 18
- OP 3A; Power Operation To Hot Standby Unit 2; Revision 5
- OP 3B; Reactor Shutdown; Revision 40
- PB Outage Status Report; December 20, 2010 0445 Update
- PBNP Unit 2 Forced Outage List; As of December 13, 2010
- Point Beach Outage Status Report; December 16, 2010
- RESP 1.1; Rod Control System: Testing In Mode 3; Revision 15
- ROD 3.2 U2C31; PBNP ICRR Plot
- Safety Monitor 3.5a.02, PBNP unit 2; December 21, 2010 00:25
- Station Log; Mid Shift OM 1.1; December 11, 2010
- Station Log; Swing Shift OM 1.1; December 10, 2010
- Station Log; Swing Shift OM 1.1; December 12, 2010
- Support/Refute Matrix; Urgent Alarm And Non-Urgent Alarm For Rod Motion During TX 6 Performance; December 14, 2010
- TS 6; Rod Exercise Test Unit 2; Revision 32
- WO 397547-16 Work Plan; Unit 2 Rod Drive Cabinets; December 16, 2010
- WO Package 00397547; Unit 2 Rod Drive Blown Fuse in 1BD-PS Cabinet; December 10, 2010

1R22 Surveillance Testing

- 2-TS-ECCS-002 Train A; Safeguards System Venting (Monthly) Unit 2; Revision 2
- 2-TS-ECCS-002 Train B; Safeguards System Venting (Monthly) Unit 2; Revision 1
- AR01154398; NRC Industry Guidance Of Unexpected Voids Or Gas Criteria; August 11, 2009
- AR01158549; U2R30 Mode 3 UT Results – GL 08-01; October 15, 2009

- AR01160512; Post-Modification UT Exams On RHR Piping Detected Gas Voids; November 5, 2009
- AR01162336; 2SI-V-12 High Point Vent – Air Bubbles Present During Vent; November 30, 2009
- AR01166814; Gas Void – Negligible, Smaller Void Found At 2SI-V14; February 17, 2010
- AR01167433; Gas Void UT Data Collected For IC-2-SI-D01; February 25, 2010
- AR01171570; Inadequate Corrective Actions Re: Gas in LHSI System; April 13, 2010
- AR01171687; Venting At 2SI-V12 Required Approximately 5 Minutes During TS-ECCS-002; April 15, 2010
- AR01172036; Develop GAMP Sentinel Point Acceptance Criteria; April 22, 2010
- AR01175584; GAMP Void Trending Requirements Not Fully Implemented; June 17, 2010
- AR01180440; Small Gas Bubbles Noted During Unit 2 SI Venting; September 5, 2010
- AR01184382; G-04 Main Oil Filter Leak; November 13, 2010
- AR01184615, "SI Accumulator Leakage, Non-Performance of GAMP Requirements
- AR01185133; TDR G04 Engine Cool Down Timer Relay O.O.S. As Found Reading; November 29, 2010
- AR01185153; Orings Found Damaged in G-04 Thermostatic Valve; November 29, 2010
- AR01186536; TI-177, Gas Intrusion Inspection Follow-up Discussion; December 21, 2010
- ASME OM Code-1995; Code For Operation And Maintenance Of Nuclear Power Plants; Revision of ASME OM Code-1990
- Calculation Signature Sheet for Calculation No. 2010-0006; Vent Flow From ECCS Common Suction Piping Vents; Revision 0
- CAP01184377; G-04 F-178B Fuel Oil Filter Gasket Leak During Restoration; November 18, 2010
- CE01154619-01; Excessive Gas Vented From 1P-15B Discharge Vent; September 1, 2009
- Drawing PB 02 MSIK00000154; P&ID Safety Injection System Unit 2; January 30, 2009
- FPL-1; Quality Assurance Topical Report; Revision 8
- Gas Accumulation Management Program (GAMP); Revision 0
- Gas Accumulation Management Program (GAMP); Revision 1 Draft A
- L-2008-076; Memo From Florida Power & Light Company to Document Control Desk, Subject: Extension Request Regarding The Three Month Response To NRC Generic Letter 2008-01, "Managing Gas Accumulation In Emergency Core Cooling, Decay Heat Removal, And Containment Spray Systems;" April 9, 2008
- LI-AA-201; Regulatory Inspection Evaluation And Assist Preparation And Response; Revision 1
- NEI 09-10; Guidelines For Effective Prevention And Management Of System Gas Accumulation; Revision 0
- NP 1.2.3; Temporary Procedure Changes; Revision 24
- NRC 2008-0019; 10 CFR 50.54(f); Memo From FPL Energy Point Beach to Document Control Desk, Subject: Three Month Response To NRC Generic Letter 2008-01, "Managing Gas Accumulation In Emergency Core Cooling, Decay Heat Removal, And Containment Spray Systems;" May 12, 2008
- NRC 2008-0075; 10 CFR 50.54(f); Memo From FPL Energy Point Beach to Document Control Desk, Subject: Nine Month Response To NRC Generic Letter 2008-01, "Managing Gas Accumulation In Emergency Core Cooling, Decay Heat Removal, And Containment Spray Systems;" October 14, 2008
- NRC 2009-0015; 10 CFR 50.54(f); Memo From FPL Energy Point Beach to Document Control Desk, Subject: Point Beach Nuclear Plant, Unit 1, Nine-Month Supplemental (Post-Outage) Response to NRC Generic Letter 2008-01; February 11, 2009

- NRC 2010-0026; 10 CFR 50.54(f); Memo From FPL Energy Point Beach to Document Control Desk, Subject: Point Beach Nuclear Plant, Unit 2, Nine-Month Supplemental (Post-Outage) Response to NRC Generic Letter 2008-01; March 5, 2010
- NRC Generic Letter 2008-01; Managing Gas Accumulation In Emergency Core Cooling, Decay Heat Removal, And Containment Spray Systems; January 11, 2008
- NRC Inspection Question No. 7; 2010 TI-177 Gas Intrusion Inspection; June 17, 2010
- NRC Inspection Question No. 7a; 2010 TI-177 Gas Intrusion Inspection; June 22, 2010
- NRC/NEIL/ANI Inspection Challenge Board Report; Inspection GL 2008-1/TI-177; June 7, 2010
- PCR1184234 for RMP 9043-43; Emergency Diesel Generator Mechanical Inspection; November 11, 2010
- PCR1184407 for RMP 9043-47A; Emergency Diesel Generator G-04 Post-Maintenance Run And Testing; November 14, 2010
- Procedure Record And Field Copy Tracking For Procedure Number IT 04 Train A; October 19, 2010
- Procedure Record for 1-TS-ECCS-002 Train A; Safeguards System Venting (Monthly) Unit 1; July 13, 2010
- Procedure Record for 1-TS-ECCS-002 Train A; Safeguards System Venting (Monthly) Unit 1; July 25, 2010
- Procedure Record for 1-TS-ECCS-002 Train A; Safeguards System Venting (Monthly) Unit 1; August 23, 2010
- Procedure Record for 1-TS-ECCS-002 Train A; Safeguards System Venting (Monthly) Unit 1; August 29, 2010
- Procedure Record for 1-TS-ECCS-002 Train A; Safeguards System Venting (Monthly) Unit 1; September 4, 2010
- Procedure Record for 1-TS-ECCS-002 Train A; Safeguards System Venting (Monthly) Unit 1; September 28, 2010
- Procedure Record for 1-TS-ECCS-002 Train A; Safeguards System Venting (Monthly) Unit 1; October 24, 2010
- Procedure Record for 1-TS-ECCS-002 Train B; Safeguards System Venting (Monthly) Unit 1; July 13, 2010
- Procedure Record for 1-TS-ECCS-002 Train B; Safeguards System Venting (Monthly) Unit 1; July 25, 2010
- Procedure Record for 1-TS-ECCS-002 Train B; Safeguards System Venting (Monthly) Unit 1; August 23, 2010
- Procedure Record for 1-TS-ECCS-002 Train B; Safeguards System Venting (Monthly) Unit 1; September 7, 2010
- Procedure Record for 1-TS-ECCS-002 Train B; Safeguards System Venting (Monthly) Unit 1; October 3, 2010
- Procedure Record for 1-TS-ECCS-002 Train B; Safeguards System Venting (Monthly) Unit 1; November 2, 2010
- Procedure Record for 2-TS-ECCS-002 Train A; Safeguards System Venting (Monthly) Unit 2; July 8, 2010
- Procedure Record for 2-TS-ECCS-002 Train A; Safeguards System Venting (Monthly) Unit 2; August 1, 2010
- Procedure Record for 2-TS-ECCS-002 Train A; Safeguards System Venting (Monthly) Unit 2; August 28, 2010
- Procedure Record for 2-TS-ECCS-002 Train A; Safeguards System Venting (Monthly) Unit 2; September 3, 2010
- Procedure Record for 2-TS-ECCS-002 Train A; Safeguards System Venting (Monthly) Unit 2; September 24, 2010

- Procedure Record for 2-TS-ECCS-002 Train A; Safeguards System Venting (Monthly) Unit 2; October 19, 2010
- Procedure Record for 2-TS-ECCS-002 Train A; Safeguards System Venting (Monthly) Unit 2; November 9, 2010
- Procedure Record for 2-TS-ECCS-002 Train B; Safeguards System Venting (Monthly) Unit 2; July 8, 2010
- Procedure Record for 2-TS-ECCS-002 Train B; Safeguards System Venting (Monthly) Unit 2; August 1, 2010
- Procedure Record for 2-TS-ECCS-002 Train B; Safeguards System Venting (Monthly) Unit 2; August 31, 2010
- Procedure Record for 2-TS-ECCS-002 Train B; Safeguards System Venting (Monthly) Unit 2; September 16, 2010
- Procedure Record for 2-TS-ECCS-002 Train B; Safeguards System Venting (Monthly) Unit 2; September 5, 2010
- Procedure Record for 2-TS-ECCS-002 Train B; Safeguards System Venting (Monthly) Unit 2; October 10, 2010
- Procedure Record for 2-TS-ECCS-002 Train B; Safeguards System Venting (Monthly) Unit 2; November 9, 2010
- Procedure Record for 2-TS-ECCS-002 Train B; Safeguards System Venting (Monthly) Unit 2; April 15, 2010
- Procedure Record For RMP 9043-47A; Emergency Diesel Generator G-04 Post-Maintenance Run; November 13, 2010
- Quick Hit No. PBSA-ENG-10-16; TI-177 Gas Accumulation Inspection (GL 2008-01); June 10, 2010
- RMP 9043-27A; Emergency Diesel Generator G-02 Post-Maintenance Run and Testing; Revision 5
- RMP 9043-37A; Emergency Diesel Generator G-03 Post-Maintenance Run and Testing; Revision 3
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- HPIP 8.1; Radioactive Source Inventory; Revision 06
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- Maintenance Rework Rate Indicator Report, November 2010
- Maintenance Department Clock Reset Report, December 21, 2010
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- Procedure NP 8.4.16; PBNP High Energy Line Break Barriers/Vent Paths, Revision 0
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- Procedure EOP-0 Unit 1; Reactor Trip Or Safety Injection; Revision 53
- Procedure EOP-1 Unit 1; Loss of Reactor Or Secondary Coolant; Revision 39
- Procedure EOP-2 Unit 1; Faulted Steam Generator Isolation; Revision 21
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- Engineering Department Performance Indicators and System Health Reports; September 2010
- Point Beach Equipment Out Of Service Log; December 21, 2010
- Mechanical Train Unavailability Report; 3rd Quarter 2010

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- AR01168334; Non-Compliance With NP 8.4.16 HELB Requirements; March 4, 2010
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- Self Evaluation Summary Report: 1st Period 2010; August 2, 2010
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- AR01175650; Unit 2 Auto Turbine Trip And Manual Reactor Trip; June 19, 2010
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- CL 2E; Mode 3 To Mode 2 Checklist; June 19, 2010
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- NP 5.3.3; Incident Investigation And Post-Trip Review; July 10, 2010
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- WO Package 00390628 04; 102-1/TG-01 (Unit 2) – Remove Trip For 3rd Harmonic Issues; June 20, 2010

LIST OF ACRONYMS USED

ACE	Apparent Cause Evaluation
ADAMS	Agencywide Document Access Management System
AO	Auxiliary Operator
ASME	American Society of Mechanical Engineers
CA	Corrective Action
CAP	Corrective Action Program
CCW	Component Cooling Water
CFR	Code of Federal Regulations
CLB	Current Licensing Basis
CR	Condition Report
DBD	Design Basis Document
DRP	Division of Reactor Projects
EAL	Emergency Action Level
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EP	Emergency Plan
ESFAS	Engineered Safety Feature Actuation System
FSAR	Final Safety Analysis Report
FW	Feedwater
GAMP	Gas Accumulation Management Program
GL	Generic Letter
HELB	High Energy Line Break
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Inspection Report
IST	Inservice Test
kV	Kilovolt
LER	Licensee Event Report
LLC	Limited Liability Corporation
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NFPA	National Fire Protection Association
NRC	U.S. Nuclear Regulatory Commission
OWA	Operator Workaround
ODCM	Offsite Dose Calculation Manual
PARS	Publicly Available Records
PI	Performance Indicator
PI&R	Problem Identification and Resolution
PM	Post-Maintenance
RCA	Radiologically Controlled Area
RG	Regulatory Guide
RHR	Residual Heat Removal
RIS	Regulatory Issue Summary
RPS	Reactor Protection System
SDP	Significance Determination Process
SDS	Steam Dump System
SRA	Senior Reactor Analyst
SI	Safety Injection
SRO	Senior Reactor Operator

SSC	Structure, System, and Component
SW	Service Water
TAR	Technical Assessment for Reportability
TCSD	Turbine Crossover Steam Dump
TDAFW	Turbine-Driven Auxiliary Feedwater
TS	Technical Specification
URI	Unresolved Item
UT	Ultrasonic Testing
WO	Work Order

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Sincerely,

/RA/

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

Docket Nos. 50-266; 50-301
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Letter to L. Meyer from M. Kunowski dated February 10, 2011

SUBJECT: POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2 NRC INTEGRATED INSPECTION REPORT 05000266/2010005; 05000301/2010005

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