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

May 10, 2013

Mr. Vito Kaminskas
Site Vice President
FirstEnergy Nuclear Operating Company
Perry Nuclear Power Plant
P. O. Box 97, 10 Center Road, A-PY-A290
Perry, OH 44081-0097

SUBJECT: PERRY NUCLEAR POWER PLANT - NRC INTEGRATED INSPECTION REPORT 05000440/2013002

Dear Mr. Kaminskas:

On March 31, 2013, the U.S. Nuclear Regulatory Commission (NRC) completed a baseline inspection at your Perry Nuclear Power Plant Unit 1. The enclosed inspection report documents the inspection results discussed on April 8, 2013, 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.

Four self-revealed findings of very low safety significance (Green) were identified during this inspection. Three of these findings were determined to involve violations of NRC requirements. The NRC is treating these violations as non-cited violations (NCVs) in accordance with Section 2.3.2 of the NRC Enforcement Policy.

If you contest these NCVs, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies 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 Perry Nuclear Power Plant.

If you disagree with a cross-cutting aspect assignment 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 Perry Nuclear Power 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 Agencywide Document Access and Management System (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Michael Kunowski, Chief
Branch 5
Division of Reactor Projects

Docket No. 05000440
License No. NPF-58

Enclosure: Inspection Report 05000440/2013002
w/Attachment: Supplemental Information

cc w/encl: Distribution via ListServ™

U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-440
License No:	NPF-58
Report No:	05000440/2013002
Licensee:	FirstEnergy Nuclear Operating Company (FENOC)
Facility:	Perry Nuclear Power Plant, Unit 1
Location:	North Perry, Ohio
Dates:	January 1, 2013, through March 31, 2013
Inspectors:	M. Marshfield, Senior Resident Inspector J. Nance, Resident Inspector D. Jones, Reactor Inspector
Approved by:	Michael Kunowski, Chief Branch 5 Division of Reactor Projects

Enclosure

TABLE OF CONTENTS

SUMMARY OF FINDINGS

Inspection Report (IR) 05000440/2013002, 01/01/2013 – 03/31/2013; Perry Nuclear Power Plant, Unit 1; Maintenance Risk Assessments and Emergent Work Control, Refueling Outage, Surveillance Testing, and Problem Identification and Resolution.

This report covers a 3-month period of inspection by resident inspectors and announced baseline inspections by a regional inspector. Four Green findings were identified. Three of the findings were considered non-cited violations (NCVs) of NRC regulations. The significance of most findings is indicated by their color (Green, White, Yellow, Red) and determined using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process," (SDP) dated June 2, 2011; the cross-cutting aspects are determined using IMC 0310, "Components Within the Cross-Cutting Areas," dated October 28, 2011. Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy, dated January 28, 2013. 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 self-revealed finding of very low safety significance was identified for the licensee's failure to implement recommended preventive maintenance on a balance-of-plant (BOP) inverter and static transfer switch. Specifically, the licensee failed to implement vendor-recommended preventive maintenance requirements to replace circuit cards in both a BOP inverter and an associated static transfer switch every twelve and ten years, respectively. No violation of NRC regulatory requirements was identified because the performance deficiency involved nonsafety-related equipment. The licensee entered this issue into the corrective action program as Condition Report 2013-00954.

The inspectors determined that the failure to perform preventive maintenance on the failed BOP inverter and static transfer switch in accordance with vendor recommendations was a performance deficiency. The performance deficiency was evaluated using Inspection Manual Chapter (IMC) 0612, Appendix B, "Issue Screening," dated September 7, 2012, and was determined to be more than minor, and thus a finding, because it was associated with the equipment performance attribute of the Initiating Events cornerstone and adversely affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. The finding was evaluated using IMC 0609, dated June 2, 2011, and IMC 0609, Attachment 0609.04, dated June 19, 2012, and IMC 0609, Appendix A, Exhibit 1 – Initiating Events Screening Questions, dated June 19, 2012. In answering "no" to "B. Transient Initiators, 'Did the finding cause a reactor trip AND the loss of mitigation equipment relied upon to transition the plant from the onset of the trip to a stable shutdown condition?,'" the inspectors determined that the finding was of very low safety significance (Green). The finding has a cross-cutting aspect in the area of problem identification and resolution associated with the corrective action program component in that the licensee failed to thoroughly evaluate problems such that the resolution addressed the causes. Specifically, the licensee had previously identified the reliability of the BOP inverter and static transfer switch as the cause for previous feedwater-related events but failed to implement recommended corrective actions to prevent future events (P.1(c)). (Section 4OA2.3)

Cornerstone: Mitigating Systems

Green. A self-revealed finding of very low safety significance and associated non-cited violation of Technical Specification 5.4.1.a., "Procedures," was identified for the licensee's failure to establish and maintain a correct surveillance inspection procedure for high-pressure core spray (HPCS) emergency core cooling systems integrated testing. The surveillance procedure used for the HPCS, safety-related electrical bus, EH13, testing during refueling outage 14, directly resulted in an unplanned outage of the bus for nearly 4 hours. The licensee entered the issue into the corrective action program as Condition Report 2013-03863.

The inspectors determined that the failure to develop a correct surveillance procedure required by Technical Specification 5.4.1 a. was a performance deficiency and resulted in an unplanned loss of the EH13 safety-related electric bus and caused a loss of function for HPCS. The performance deficiency was determined to be more than minor, and thus a finding, using IMC 0612, Appendix B, "Issue Screening," dated September 7, 2012, because it was associated with the equipment performance attribute of the Mitigating Systems cornerstone and adversely 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 evaluated for significance using IMC 0609, Attachment 0609.04, dated June 19, 2012, and IMC 0609, Appendix A, Exhibit 2 – Mitigating Systems Screening Questions, dated June 19, 2012. The inspectors answered "yes" to Question 2, "Does the finding represent a loss of system and/or function?" A detailed risk evaluation was conducted by the Region III Senior Reactor Analyst (SRA). The SRA performed an evaluation using the NRC's Standardized Plant Analysis Risk model for Perry. The SRA assumed that EH13 was unavailable for 4 hours. The change in core damage frequency was estimated to be much less than 1E-6/yr, which represents a finding of very low safety significance (Green). The finding has a cross-cutting aspect in the area of human performance associated with the work control component, in that, the licensee failed to appropriately coordinate work activities by incorporating actions to address the impact of changes to the work scope or activities which could affect the plant. Specifically, the development of a new surveillance procedure did not correctly predict the plant response for the safety-related system test lineup and resulted in an unplanned loss of the EH13 safety-related electric bus (H.3(b)). (Section 1R13)

Green. A self-revealed finding of very low safety significance and associated non-cited violation of Technical Specification 5.4.1.a., "Procedures," was identified for the licensee's failure to correctly implement a surveillance procedure for calibration of a scram discharge volume (SDV) level detector. Specifically, licensee technicians failed to open and lock open, with independent verification, the lower isolation valve to an SDV level detector. The licensee documented the issue in the corrective action program as Condition Report 2013-04452.

The inspectors determined that the failure to correctly complete the procedure and lock open the lower isolation valve was a performance deficiency which resulted in a locked-in scram signal with a resulting inability to clear the signal and restore safety-related systems after the scram (to begin a refueling outage) for several days. The performance deficiency was evaluated under Inspection Manual Chapter (IMC) 0612, Appendix B, “Issue Screening,” dated September 7, 2012, and determined to be more than minor, and thus a finding, because it was associated with the human performance attribute of the Mitigating Systems cornerstone and it adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). The finding was evaluated for significance using IMC 0609, Attachment 0609.04, dated June 19, 2012, and IMC 0609, Appendix A, Exhibit 2, “Mitigating Systems Screening Questions,” dated June 19, 2012. By answering “no” to “C. Reactivity Control Systems,” questions 1, 2, and 3, the inspectors determined this finding was of very low safety significance because the finding did not affect other diverse methods of reactor shutdown, it did not add positive reactivity, nor did it result in the mismanagement of reactivity by an operator. The finding has a cross-cutting aspect in the area of human performance associated with the work practices component, in that the licensee communicates human error prevention techniques, that techniques are used commensurate with the risk of the assigned task, and personnel do not proceed in the face of uncertainty or unexpected circumstances. Specifically, the independent verifier found the valve in an unexpected condition with a locking device already installed, did not stop the process and question the valve position, but proceeded in the face of uncertainty (H.4(a)). (Section 1R20)

Green. A self-revealed finding of very low safety significance and associated non-cited violation of 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” was identified when the licensee failed to correctly implement procedures for testing safety-related equipment. Specifically, the licensee failed to correctly implement prerequisite steps in a surveillance instruction, causing the standby liquid control (SLC) pump 'A' plunger pot drain valves to be left open, contrary to procedure. The licensee entered the finding into the corrective action program as Condition Report 2013-00114 and took immediate action to close the valves when leakage was discovered from the drain valve tailpipes.

The inspectors determined that the failure to correctly complete the prerequisite steps in surveillance instruction (SVI)-C41-T2001-A was a performance deficiency which resulted in a water spill in containment, an associated lockup of the rod control and information system (RCIS), and required the licensee to enter two off-normal instructions (ONIs). The performance deficiency was determined to be more than minor, and thus a finding, using Inspection Manual Chapter (IMC) 0612, Appendix E, “Examples of Minor Issues,” dated August 11, 2009, because it is similar to Example 4.b and resulted in an unexpected, “Inhibit Rod Motion RCIS OOS,” alarm and caused the operating crew to enter ONI-C11-1, “Inability to Move Control Rods.” The finding was evaluated for significance using IMC 0609, Attachment 0609.04, dated June 19, 2012, and IMC 0609, Appendix A, Exhibit 2, “Mitigating Systems Screening Questions,” dated June 19, 2012. In answering “no” to “C. Reactivity Control Systems,” questions 1, 2, and 3, the inspectors determined that the finding was of very low safety significance because the finding did not affect a reactor protection system trip signal, did not add positive reactivity, nor did it result in the mismanagement of reactivity by an operator. The finding has a cross-cutting aspect in the area of human performance associated with the work practices component, in that licensee personnel failed to use human error prevention techniques, such as holding a pre-job briefing, self and peer checking, and proper documentation of activities. Specifically, the operation to position the plunger pot drain valves on the 'A' and 'B' SLC pumps was not coordinated by the field supervisor in accordance with the SVI and operations personnel proceeded in the face of uncertainty or unexpected circumstances (H.4(a)). (Section 1R22)

B. Licensee-Identified Violations

No findings were identified.

REPORT DETAILS

Summary of Plant Status

The plant began the inspection period at 100 percent power. On January 22, 2013, at 3:32 a.m. an unplanned automatic reactor scram occurred due to a reactor pressure vessel (RPV) level 3 initiation signal. The reactor was returned to criticality on January 26 at 12:34 p.m. The plant synchronized to the grid on January 27 at 3:43 p.m. and reached 100 percent power on February 1. Plant power began to decrease on February 7 due to end-of-core life prior to refueling outage (RFO) 1R14. Plant power coastdown continued until March 18, when at 12:01 a.m., the plant disconnected from the grid and was shutdown for RFO 1R14. The plant remained shutdown for RFO 1R14 at the end of the quarter.

1. REACTOR SAFETY

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

1R01 Adverse Weather Protection (71111.01)

External Flooding

a. Inspection Scope

The inspectors evaluated the design, material condition, and procedures for coping with the design basis probable maximum flood. The evaluation included a review to check for deviations from the descriptions provided in the Updated Safety Analysis Report (USAR) for features intended to mitigate the potential for flooding from external factors. As part of this evaluation, the inspectors checked for obstructions that could prevent draining, checked that the accessible roofs did not contain obvious loose items that could clog drains in the event of heavy precipitation, and determined that barriers required to mitigate the flood were in place and operable. Additionally, the inspectors performed a walkdown of the protected area to identify any modification to the site which would inhibit site drainage during a probable maximum precipitation event or allow water ingress past a barrier. The inspectors also walked down underground bunkers and manholes subject to flooding that contained multiple train or multiple function risk-significant cables. The inspectors also reviewed the site procedures for mitigating the probable maximum precipitation event. Specific documents reviewed during this inspection are listed in the Attachment to this report.

This inspection constituted one external flooding sample as defined in Inspection Procedure (IP) 71111.01-05.

b. Findings

No findings were identified.

1R04 Equipment Alignment (71111.04Q)

a. Inspection Scope

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

- 'B' standby liquid control (SLC) system;
- 'A' residual heat removal (RHR) system;
- 125-Volt direct current (Vdc) Division 1; and
- Low-pressure core spray (LPCS) system.

The inspectors selected these systems based on their risk significance relative to the Reactor Safety Cornerstones at the time they were inspected. The inspectors attempted to identify any discrepancies that could impact the function of the system and, therefore, potentially increase risk. The inspectors reviewed applicable operating procedures, system diagrams, USAR, 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 systems incapable of performing their intended functions. The inspectors also walked down accessible portions of the systems to verify system components and support equipment were aligned correctly and operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious deficiencies. The inspectors also verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the corrective action program (CAP) with the appropriate significance characterization. Documents reviewed are listed in the Attachment to this report.

These activities constituted four partial system walkdown samples as defined in IP 71111.04-05.

b. Findings

No findings were identified.

1R05 Fire Protection (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 Zones 1CC-3c and 1DG-1c (Control Complex Unit 1 - Division 1 Emergency Diesel Generator (EDG) Room and Division 1 4160-V and 480-V Switchgear Room);
- Fire Zones 1CC-4g and h (Control Complex Division 1 125-Vdc Distribution and Battery Rooms);
- Fire Zones 1CC-6 and 2CC-6 (Control Complex Heating/Ventilation and Air Conditioning Systems Trains A and B);

- Fire Zones 1AB-1a, f, and g (Auxillary Building 574' – LPCS, High-Pressure Core Spray (HPCS), General Hallway); and
- Fire Zone 0IB-3 (Intermediate Building 620' General Hallway).

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 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 five quarterly fire protection inspection samples as defined in IP 71111.05-05.

b. <u>Findings</u>

No findings were identified.

1R08 Inservice Inspection Activities (71111.08G)

From March 25 through March 28, 2013, the inspectors conducted a review of the implementation of the licensee's Inservice Inspection (ISI) Program for monitoring degradation of the reactor coolant system, risk significant piping and components, and containment systems.

The inservice inspections described in Sections 1R08.1 and 1R08.2 below constituted one inspection sample as defined in IP 71111.08-05.

.1 Piping Systems ISI

a. Inspection Scope

The inspectors observed and/or reviewed the following non-destructive examinations mandated by the American Society of Mechanical Engineers (ASME) Section XI Code to evaluate compliance with the ASME Code Section XI and Section V requirements and if any indications and defects were detected, to determine if these were dispositioned in accordance with the ASME Code or an NRC-approved alternative requirement.

- Ultrasonic Examination (UT) of the RHR heat exchanger 18"-diameter flange-to-pipe weld, Report No. UT-13-E001;
- UT of the RHR shell-flange-to-shell-cylinder weld, Report No. UT-13-E013;

- UT of the LPCS 24" pipe to flange weld, Report No. UT-13-E011;
- UT of the RHR 12" pipe to 12" x 12"x 12" Tee weld (1E12-0417), Report No. UT-13-E017;
- UT of the RHR 24" pipe to 12" x 12" x 12" Tee weld (1E12-0390), Report No. UT-13-E019;
- Magnetic Particle Examination of LPCS 24" pump suction pipe longitudinal seam; Report No. 0942-13A-006; and
- Visual Examination of the IP42 heat exchanger anchor (WA), Report No. 1042-13-005.

During the prior RFO (1R13) non-destructive surface and volumetric examinations, the licensee did not identify any relevant/recordable indications. Therefore, no NRC review was completed for this inspection procedure attribute.

The inspectors reviewed the pressure boundary weld completed for the removal and replacement of reactor core isolation cooling (RCIC) valve 1E51F0022, WO No. 200389452, a risk-significant system, since the beginning of the last RFO to determine if the licensee applied the preservice non-destructive examinations and acceptance criteria required by the ASME Code Section XI. Additionally, the inspectors reviewed the welding procedure specification and supporting weld procedure qualification records to determine if the weld procedure was qualified in accordance with the requirements of Construction Code and the ASME Code Section IX.

b. Findings

No findings were identified.

.2 Identification and Resolution of Problems

a. Inspection Scope

The inspectors performed a review of ISI-related problems entered into the licensee's CAP and conducted interviews with licensee staff to determine if:

- the licensee had established an appropriate threshold for identifying ISI-related problems;
- the licensee had performed a root cause (if applicable) and taken appropriate corrective actions; and
- the licensee had evaluated operating experience and industry generic issues related to ISI and pressure boundary integrity.

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

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification and Licensed Operator Performance (71111.11Q)

.1 Resident Inspector Quarterly Review of Licensed Operator Requalification

a. Inspection Scope

On January 14, the inspectors observed a crew of licensed operators in the plant's simulator during licensed operator requalification training to verify that operator performance was adequate, evaluators were identifying and documenting 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 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 sample for the licensed operator requalification program simulator as defined in IP 71111.11-05.

b. Findings

No findings were identified.

.2 Resident Inspector Quarterly Observation of Heightened Activity or Risk

a. Inspection Scope

On January 22, the inspectors observed licensed operation's personnel during post-automatic scram activities. This was an activity that required heightened awareness or was related to increased risk. The inspectors evaluated licensed operator performance in the following areas:

- crew's clarity and formality of communications;
- ability to take timely conservative actions;
- prioritization, interpretation, and verification of trends/alarms;
- correct use and implementation of procedures;
- control board/component manipulations;
- oversight and direction from supervisors;
- ability to identify and implement appropriate TS actions and emergency operating procedures, actions, and notifications;
- documentation of activities; and

- pre-activity and post-activity briefs and use of human error prevention techniques.

The performance in these areas was compared to pre-established operator action expectations, procedural compliance and task completion requirements. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one quarterly sample for licensed operator heightened activity/risk as defined in IP 71111.11-05.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12Q)

a. Inspection Scope

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

- intermediate range monitoring system 'B'; and
- suppression pool make-up system.

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/functions classified as (a)(2), or appropriate and adequate goals and corrective actions for systems classified as (a)(1).

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

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

b. Findings

No findings were identified.

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

a. Inspection Scope

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

- shutdown risk for plant trip;
- RHR 'A' chemical decontamination process;
- essential service water pump 'A' discharge valve maintenance;
- RHR 'A' chemical decontamination resin transfer to radwaste spent resin tank; and
- HPCS emergency core cooling system (ECCS) integration test.

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

Specific documents reviewed during this inspection are listed in the Attachment to this report. These maintenance risk assessments and emergent work control activities constituted five samples as defined in IP 71111.13-05.

b. Findings

Introduction: A self-revealed Green finding and associated non-cited violation (NCV) of TS 5.4.1 a., “Procedures,” was identified for the licensee’s failure to establish and maintain a correct surveillance inspection procedure for HPCS ECCS integrated testing. The surveillance procedure used for the HPCS, safety-related electrical bus, EH13, testing during RFO 1R14 directly resulted in an unplanned outage of the bus for nearly 4 hours.

Description: On March 14, 2013, power was lost to the Division 3 safety-related electrical bus, EH13, for almost 4 hours following an attempt to test the loss of offsite power (LOOP) function of the bus. The introduction of a LOOP signal to EH13's protection circuitry caused the preferred source breaker, EH1303, which was supplying the EH13 bus, to trip open as expected. However, the alternate preferred source breaker, EH1302, did not trip open, as it should have. The HPCS EDG started as required by the test but the output breaker did not close onto the EH13 bus because the system still had a signal that the alternate preferred breaker, EH1302, was closed. This simulated closed indication was telling the output breaker that the bus was still energized. The operators took immediate and appropriate action to secure the HPCS diesel since the Division 3 essential service water pump which cools the diesel engine had no power from the real de-energized EH13 bus. The operating crew also entered several TS Action Statements as a result of the sustained loss of bus EH13, including TS 3.6.1.3 Action Statements A.1 and A.2 for 6 containment isolation valves that were de-energized due to real loss of power from EH13, and entered Off-Normal Instruction (ONI) R-22-1 for the loss of bus EH13.

Subsequently, the licensee identified that during a rewrite of the surveillance document, to support RFIO 14, the licensee had adopted a different methodology for closing the alternate preferred source breaker in the test position. This change in methodology was intended to reduce the potential for human error from the previous methodology of installing and removing a jumper and an additional switch positioning requirement. The new methodology utilized the local test switch at EH1302 to close the breaker, followed by tying down the cell switch to simulate the breaker racked in. The developer of the new procedure did not recognize that the new methodology would not close a holding contact in the breaker trip circuitry which is in series with the LOOP logic contacts. The holding contact is only closed when the breaker control switch in the control room is taken to the close position as was required in the previous methodology used for this surveillance procedure. The SVI was again revised, to correct the errors found. The bus was re-energized approximately 4 hours following its initial loss and all systems were returned to their required configurations. The licensee entered this issue into the CAP as CR 2013-03863.

<u>Analysis</u>: The inspectors determined that the failure to establish and maintain a procedure for testing the HPCS ECCS, as required by TS 5.4.1.a., was a performance deficiency and resulted in an unplanned loss of the EH13 safety-related electrical bus. The inspectors determined that the performance deficiency was not similar to any examples in Inspection Manual Chapter (IMC) 0612, Appendix E, “Examples of Minor Issues.” The inspectors determined in accordance with IMC 0612, Appendix B, “Issue Screening,” that the deficiency was more than minor, and thus a finding, because it was associated with the equipment performance attribute of the Mitigating Systems cornerstone and adversely 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 evaluated for significance using IMC 0609, Attachment 0609.04, and IMC 0609, Appendix A, Exhibit 2 – Mitigating Systems Screening Questions. The inspectors answered “yes” to Question 2, “Does the finding represent a loss of system and/or function?” and a detailed risk evaluation was conducted as required by the Region III Senior Reactor Analysts (SRAs). The SRAs performed an evaluation using the NRC’s SPAR model for Perry. The SRA assumed that safety-related bus EH13 was unavailable for 4 hours. The change in core damage frequency (CDF) was estimated to be much less than 1E-6/yr, which indicates a finding of very low safety significance (Green). The dominant sequence was a station blackout event followed by the failure to recover offsite and emergency power.

The finding has a cross-cutting aspect in the area of human performance associated with the work control component, in that, the licensee failed to appropriately coordinate work activities by incorporating actions to address the impact of changes to the work scope or activities which could affect the plant. Specifically, the development of a new surveillance procedure did not correctly predict the plant response for the safety-related system test lineup and resulted in an unplanned loss of the EH13 safety-related electrical bus (H.3(b)).

Enforcement: Technical Specification 5.4.1 a., "Procedures," requires that procedures be established, implemented, and maintained as recommended in Appendix A of Regulatory Guide 1.33, Revision 2. Regulatory Guide 1.33 requires that specific procedures be written for surveillance tests and inspections of boiling water reactor ECCS tests. Contrary to this, Perry procedure, SVI-E22-T2680, "HPCS ECCS Integrated Test," failed to establish appropriate plant conditions for Division 3 LOOP testing and resulted in a loss of the EH13 safety-related bus. This issue was entered into the CAP as CR 2013-03863 and the licensee took immediate actions to return the plant to a normal condition prior to conducting further testing and corrected the SVI procedure to reflect actual plant response functions. Because this violation was of very low safety significance and was entered into the licensee's CAP, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. **(NCV 05000440/2013002-01, Inadequate Procedure Resulted in Loss of High-Pressure Core Spray Function)**

1R15 Operability Determinations and Functionality Assessments (71111.15)

a. Inspection Scope

The inspectors reviewed the following issues:

- Division 2 EDG operability with multiple annunciator alarms locked in;
- RPV operability determination;
- Operational Decision Making Instruction (ODMI) for plant operations with DB-1-A, non-essential vital power inverter not in service;
- helicoil-threaded repairs to main steam safety relief valve inlet and outlet flange bolt holes; and
- fuel pool cooling and cleanup relief valve repairs requiring prompt functionality assessment because of excessive system leakage issues.

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 TS and USAR 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 corrective action documents to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings were identified.

1R18 Plant Modifications (71111.18)

a. Inspection Scope

The inspectors reviewed the temporary modifications implemented for RHR 'A' chemical decontamination.

The inspectors reviewed the configuration changes and associated 10 CFR 50.59 safety evaluation screening against the design basis, the USAR, and TSs, as applicable, to verify that the modification did not affect the operability or availability of the affected systems. The inspectors, as applicable, observed ongoing and completed work activities to ensure that the modifications were installed as directed and consistent with the design control documents; the modifications operated as expected; post-modification testing adequately demonstrated continued system operability, availability, and reliability; and that operation of the modifications did not impact the operability of any interfacing systems. As applicable, the inspectors verified that relevant procedure, design, and licensing documents were properly updated. Lastly, the inspectors discussed the plant modification with operations, engineering, and training personnel to ensure that the individuals were aware of how operations with the plant modification in place could impact overall plant performance. Documents reviewed in the course of this inspection are listed in the Attachment to this report.

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

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

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

- SLC storage tank level instrument vent valve and reference leg vent valve replacements;
- RCIC remote shutdown controller replacement retest;
- 'A' RHR chemical decontamination restoration activities; and
- Division 3 EDG slow start test.

These activities were selected based upon the structure, system, or component's ability to impact risk. The inspectors evaluated these activities for the following (as applicable): the effect of testing on the plant had been adequately addressed; testing was adequate for the maintenance performed; acceptance criteria were clear and demonstrated operational readiness; test instrumentation was appropriate; tests were performed as written in accordance with properly reviewed and approved procedures; equipment was returned to its operational status following testing (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 USAR, 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 corrective action documents associated with post-maintenance tests to determine whether the licensee was identifying problems and entering them in the CAP and that the problems were being corrected commensurate with their importance to safety. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings were identified.

1R20 Outage Activities (71111.20)

.1 Refueling Outage Activities

a. Inspection Scope

The inspectors reviewed the Outage Safety Plan (OSP) and contingency plans for Perry's Unit 1 RFO, to be conducted March 18 to May 2, to confirm that the licensee had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth. During the RFO, the inspectors observed portions of the shutdown and cooldown processes and monitored licensee controls over the outage activities listed below:

- licensee configuration management, including maintenance of defense-in-depth commensurate with the OSP for key safety functions and compliance with the applicable TS when taking equipment out-of-service;
- implementation of clearance activities and confirmation that tags were properly hung and equipment appropriately configured to safely support the work or testing;
- installation and configuration of reactor coolant pressure, level, and temperature instruments to provide accurate indication, accounting for instrument error;
- controls over the status and configuration of electrical systems to ensure that TS and OSP requirements were met, and controls over switchyard activities;
- monitoring of decay heat removal processes, systems, and components;
- controls to ensure that outage work was not impacting the ability of the operators to operate the spent fuel pool cooling system;
- reactor water inventory controls, including flow paths, configurations, and alternative means for inventory addition, and controls to prevent inventory loss;
- controls over activities that could affect reactivity;
- maintenance of secondary containment as required by TS;
- licensee fatigue management, as required by 10 CFR 26, Subpart I;
- refueling activities, including fuel handling and sipping to detect fuel assembly leakage; and
- licensee identification and resolution of problems related to RFO activities.

Documents reviewed during the inspection are listed in the Attachment to this report.

These inspection activities represent activities which are portions of the RFO IP and will be counted as complete at the conclusion of RFO 1R14 as defined in IP 71111.20-05.

b. Findings

Introduction: A self-revealed Green finding and associated NCV of TS 5.4.1.a., was identified for the licensee's failure to correctly implement a surveillance procedure for calibration of a scram discharge volume (SDV) level detector. Specifically, licensee technicians failed to open and lock open, with independent verification, the lower isolation valve to an SDV level detector.

Description: On March 18, 2013, the reactor plant was scrammed during the shutdown for RFO 1R14 and the SDV high level alarm came in as expected. When the operators took the post-scram action to clear the alarm it would not clear on channel 'A' of reactor protection system 'A.' Following the setting of appropriate plant conditions to continue troubleshooting, on March 25, the licensee, determined that the inability to clear the locked-in high level alarm on channel 'A' was a direct result of the lower isolation valve for the level detector being closed (however, a locking device on the valve indicated that it was locked open). Subsequent investigation determined that the valve had last been operated on February 18 to support a calibration check of the associated level detector.

With the valve closed and the float switch for level unable to perform its function, the plant should have entered a TS that required the associated trip system to be placed in trip, and if not completed in 12 hours, the plant would have been required to go to mode 3 in the subsequent 12-hour period. Since the licensee was unaware that the valve was closed, the actions for the TS were not taken and the licensee will submit a 60-day event report. The operators took immediate corrective actions to open the valve and the high level alarm cleared. A licensee investigation identified the individuals responsible for the mis-positioning of the valve and appropriate administrative actions were taken, as well as re-training conducted with personnel in the instrumentation and controls (I&C) maintenance shop.

Analysis: The inspectors determined that the failure to correctly complete the procedure and lock open the lower isolation valve was a performance deficiency which resulted in a locked-in scram signal with a resulting inability to clear the signal and restore safety-related systems after the scram for several days. The inspectors determined that the performance deficiency was not similar to any examples in IMC 0612, Appendix E, "Examples of Minor Issues," August 11, 2009. The inspectors did determine in accordance with IMC 0612, Appendix B, "Issue Screening," dated September 7, 2012, that the issue was more than minor, and thus a finding, because it was associated with the human performance attribute of the Mitigating Systems cornerstone, and it adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). The finding was evaluated for significance using IMC 0609.04 and 0609 Appendix A, Exhibit 2 – Mitigating Systems Screening Questions. In answering "no" to "C. Reactivity Control Systems," questions 1, 2, and 3, the inspectors determined that the finding was of very low safety significance (Green) because the finding did not affect a reactor protection system trip signal, it did not add positive reactivity, nor did it result in the mismanagement of reactivity by an operator.

The finding has a cross-cutting aspect in the area of human performance associated with the work practices component, in that the licensee communicates human error prevention techniques, that techniques are used commensurate with the risk of the assigned task, and personnel do not proceed in the face of uncertainty or unexpected circumstances. Specifically, the independent verifier found the valve in an unexpected condition with a locking device already installed, did not stop the process and question the valve position, but proceeded in the face of uncertainty (H.4(a)).

Enforcement: Technical Specification 5.4.1.a., "Procedures," requires in part, that procedures be established, implemented, and maintained as recommended in Appendix A of Regulatory Guide 1.33, Revision 2. Regulatory Guide 1.33 requires that specific procedures be implemented for the conduct of system maintenance. Perry Nuclear Operating Business Practice (NOBP)-LP-2603, Event-Free Tools and Verification Practices, requires a particular method of conducting independent verification of valve position checks. Contrary to this, on February 18, 2013, technicians conducting a surveillance failed to follow the procedure and consequently left a valve in the closed position that which was required to be open. This issue was entered into the CAP as CR 2013-04452 and immediate action was taken to restore the valve to the proper position. Because this violation was of very low safety significance and was entered into the licensee's CAP, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. **(NCV 05000440/2013002-02, Valve Mis-position Causes SDV Level Detector Inoperability)**

.2 Other Outage Activities – Forced Outage

a. Inspection Scope

The inspectors evaluated outage activities for an unscheduled outage that began on January 22, 2013, and continued through January 27. The inspectors reviewed activities to ensure that the licensee considered risk in developing, planning, and implementing the outage schedule.

The inspectors observed or reviewed the reactor shutdown and cooldown, outage equipment configuration and risk management, electrical lineups, selected clearances, control and monitoring of decay heat removal, control of containment activities, personnel fatigue management, startup and heatup activities, and identification and resolution of problems associated with the outage. The outage followed an unplanned automatic reactor scram from 100 percent power when a failure of the nonsafety-related DB1A inverter caused a loss of reactor feedwater flow. After the scram, both HPCS and RCIC actuated to restore water level in the vessel, as designed.

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)

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:

- LPCS pump and valve inservice testing;
- RCIC pump and valve routine testing;
- 'B' SLC pump and valve routine testing;
- low-pressure core injection pump 'A' time delay functional routine testing;
- combustible gas mixing system 'A' operability routine testing; and
- end-of-cycle recirculation pump breaker routine trip test.

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

- did preconditioning occur;
- the effects of the testing were adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- acceptance criteria were clearly stated, demonstrated operational readiness, and 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 USAR, 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 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 five routine surveillance testing samples and one inservice testing sample as defined in IP 71111.22, Sections -02 and -05.

b. Findings

Introduction: A self-revealed Green finding and associated NCV of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified when the licensee failed to correctly implement procedures for testing safety-related equipment. Specifically, the licensee failed to correctly implement prerequisite steps in a surveillance instruction, causing the SLC pump 'A' plunger pot drain valves to be left open contrary to procedure.

Description: During the night shift on January 2, 2013, the prerequisites for surveillance instruction (SVI)-C41-T2001-A, "Standby Liquid Control A Pump and Valve Operability Test," were initiated; the main body steps of the SVI were to be performed the next day. During the night shift, while completing the prerequisites, the field supervisor incorrectly directed a non-licensed operator (NLO) to drain the SLC pump plunger pots using the standard steps on an operations department hand-held computer; a field copy of the SVI was not provided to the NLO. Subsequently, two plunger pot drain valves, 1C41-F553A and 1C41-F553B, were not closed as required by the prerequisites in the SVI.

The night shift field supervisor turned over to the day shift field supervisor that the prerequisites for SVI-C41-T2001-A were complete. The day shift field supervisor directed successful performance of the main body steps of the SVI through Section 5.1. While performing plant restoration in section 5.2, the NLOs lined up the SLC test tank for a chemistry sample as required by the procedure. As the valves were manipulated to obtain a sample, water flowed backwards through the plunger pot drain lines to the plunger pot stuffing box, overflowed the SLC pump 'A' stuffing box and flowed onto the floor. The water subsequently drained onto several rod control hydraulic control units on the level below the spilled water, causing an unexpected "Inhibit Rod Motion RCIS OOS [rod control and information system out of service]" alarm to lock-in for control rod 22-51 and a lockup of the rod control and information system. The plant entered off-normal instruction (ONI)-C11-1, "Inability to Move Control Rods," and ONI-ZZZ-5 for "Radioactive or Chemical Spill," due to the spilled water in containment. The mis-positioned valves were quickly identified by the operators as the source of the spill and were closed, stopping the flow of water.

Analysis: The inspectors determined that the failure to correctly complete the prerequisite steps in SVI-C41-T2001-A was a performance deficiency which resulted in a water spill in containment, an associated lockup of the rod control and information system (RCIS), and required the licensee to enter two ONIs. The inspectors determined that the performance deficiency was more than minor, and thus a finding, using IMC 0612, Appendix E, "Examples of Minor Issues," because it is similar to Example 4.b, and did result in an unexpected, “Inhibit Rod Motion RCIS OOS,” alarm, and caused the operating crew to enter ONI-C11-1, “Inability to Move Control Rods.” The finding was evaluated for significance using IMC 0609, Attachment 0609.04, and IMC 0609, Appendix A, Exhibit 2 – Mitigating Systems Screening Questions. In answering “no” to “C. Reactivity Control Systems,” questions 1, 2, and 3, the inspectors determined that the finding was of very low safety significance (Green) because the finding did not affect a reactor protection system trip signal, it did not add positive reactivity, nor did it result in the mismanagement of reactivity by an operator.

The finding has a cross-cutting aspect in the area of human performance associated with the work practices component, in that the licensee failed to use human error prevention techniques, such as holding a pre-job briefing, self and peer checking, and proper documentation of activities. Specifically, the operation to position the plunger pot drain valves on the 'A' and 'B' SLC pumps was not coordinated by the field supervisor in accordance with the SVI and operations personnel proceeded in the face of uncertainty or unexpected circumstances (H.4(a)).

Enforcement: Title 10 of the CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” states, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Surveillance Instruction C41-T2001-A, “Standby Liquid Control A Pump and Valve Operability Test,” was written in accordance with 10 CFR Part 50, Appendix B, to accomplish an activity affecting quality, and required the SLC pump 'A' an 'B' plunger pot drain valves be closed as prerequisites to performance of the surveillance test. Contrary to this, on January 3, 2013, the licensee failed to close the plunger pot valves during an activity affecting quality in accordance with the applicable instructions, procedures, and drawings. Specifically, the on-shift field supervisor failed to direct the closure of the SLC pump 'A' and 'B' plunger pot drain valves. This issue was entered into the CAP as CR 2013-00114 and the licensee took immediate action to close the valves when leakage was discovered from the drain valve tailpipes. Additionally, immediate action was taken to remove the operators from the performance of duties until they could be retrained, and the operations department acknowledged in the night orders the procedural errors made during this event. Because this violation was of very low safety significance and was entered into the licensee’s CAP, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. **(NCV 05000440/2013002-03, Failure to Follow Procedures for Conducting a Standby Liquid Control System Surveillance)**

1EP6 Drill Evaluation (71114.06)

Training Observation

a. Inspection Scope

The inspector observed a simulator training evolution for licensed operators on January 14, 2013, which required emergency plan implementation by the operations crew. This evolution was planned to be evaluated and included in performance indicator 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 71114.06-06.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

4OA1 Performance Indicator Verification (71151)

.1 Unplanned Scrams per 7000 Critical Hours

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Scrams per 7000 Critical Hours performance indicator (PI) for the first quarter 2012 through the fourth quarter 2012. To determine the accuracy of the PI data reported, PI definitions and guidance contained in Nuclear Energy Institute (NEI) Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, were used. The inspectors reviewed the licensee's operator logs, issue reports, event reports, and NRC IRs 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 one sample for unplanned scrams per 7000 critical hours as defined in IP 71151-05.

b. Findings

No findings were identified.

.2 Unplanned Scrams with Complications

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Scrams with Complications PI for the first quarter 2012 through the fourth quarter 2012. To determine the accuracy of the PI data reported, PI definitions and guidance contained in NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, were used. The inspectors reviewed the licensee's operator logs, issue reports, event reports, and NRC integrated IRs 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 one sample for unplanned scrams with complications as defined in IP 71151-05.

b. Findings

No findings were identified.

.3 Unplanned Power Changes per 7000 Critical Hours

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Power Changes per 7000 Critical Hours PI for the first quarter 2012 through the fourth quarter 2012. To determine the accuracy of the PI data reported, PI definitions and guidance contained in NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, were used. The inspectors reviewed the licensee's operator logs, issue reports, event reports, and NRC integrated IRs 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 one sample for unplanned power changes per 7000 critical hours as defined in IP 71151-05.

b. Findings

No findings were identified.

4OA2 Identification and Resolution of Problems (71152)

.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 they were being entered into the licensee's CAP at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. Attributes reviewed included: 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 occurrence reviews were proper and adequate; and that the classification, prioritization, focus, and timeliness of corrective actions were commensurate with safety and sufficient to prevent recurrence of the issue. Minor issues entered into the licensee's CAP as a result of the inspectors' observations are 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

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

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

b. Findings

No findings were identified.

.3 Selected Issue Follow-Up Inspection: Root Cause Corrective Actions for Reactor Trip in January 2013

a. Inspection Scope

The inspectors performed an in-depth review of root cause corrective actions for the reactor trip on January 22, 2013, as contained in CR 2013-01011, Inverter 1R14S0004 Was Found On Its Alternate Source and With the Fail Light On Following Reactor Scram, dated January 22, 2013. During this review the inspectors observed the corrective actions identified and interviewed personnel involved with the root cause analysis, with corrective action development, and with corrective action implementation. The licensee was not able to determine the exact root cause of the failure of the balance-of-plant (BOP) inverter and the associated static transfer switch. The corrective actions identified are consistent with the information and analysis performed to date. Several corrective actions are complete and several more are planned for RFO 1R14 which began on March 18, 2013.

This review constituted one in-depth problem identification and resolution sample as defined in IP 71152-05.

b. Findings

Introduction: A self-revealed green finding was identified for the licensee's failure to implement vendor recommended preventive maintenance requirements to replace circuit cards in both a BOP inverter and an associated static transfer switch every 12 and 10 years, respectively.

Description: On January 22, 2013, actuation of a 700-amp fuse in a BOP inverter and failure of the associated static transfer switch to immediately shift caused a loss of power to the digital feedwater control system with a subsequent loss of feedwater to the reactor which was at 100 percent power. Rapid lowering of the reactor pressure vessel (RPV) water level caused an automatic reactor scram due to an RPV level 3 activation signal of the reactor protection system. The RPV water level continued to lower to level 2, which resulted in a valid initiation of both RCIC and HPCS. The RCIC initiation provided a main turbine trip signal and a reactor feed pump turbine 'A' and 'B' trip signal, as designed for the reactor power level at the time. The RPV level 2 signal also caused the reactor recirculation pumps to trip and the reactor water cleanup system to isolate. Water level in the RPV decreased to a level of approximately 79 inches above the top of active fuel before it rapidly increased due to HPCS and RCIC injecting into the core. The control room operators regained control of water level shortly after water level reached level 8 and tripped the HPCS and RCIC pumps and maintained RPV water level in the normal hot shutdown band. Operator response to the scram was complicated by a degraded full core display caused by the electrical transient which initially caused the scram.

The licensee’s root cause team was not able to determine the exact root cause of the scram, but did determine that the most likely cause was a failed component in the static transfer switch. It was also determined by the root cause team that 2 of the 3 circuit cards in the static transfer switch were replaced in December 2012, but that the static switch sensing and transfer card was not included in the maintenance plan and the card had not been replaced since 1987, which is significantly outside the vendor’s recommended frequency of every 10 years. Based on the age of the static transfer switch sensing and transfer card, the preventive maintenance history was reviewed for both the BOP inverter and the static transfer switch, which revealed that a maintenance plan to replace circuit cards in the inverter did not exist and the maintenance plan for the static transfer switch did not include replacement of the sensing and transfer card. The vendor manual recommended replacing the BOP inverter cards every 12 years and the static transfer switch cards every 10 years. The root cause team also concluded there was an organizational and programmatic aspect to the extended age of the cards related to the lack of commitment to implementation of the preventive maintenance program.

Analysis: The failure to perform maintenance on the BOP inverter and its associated static transfer switch in accordance with vendor recommendations and licensee preventive maintenance template was a performance deficiency and was within the licensee’s ability to foresee and correct. The inspectors determined that the performance deficiency was more than minor, and thus a finding, because it was associated with the equipment reliability attribute of the Initiating Events cornerstone and adversely affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. The finding was evaluated for significance using IMC 0609, Attachment 0609.04, and IMC 0609, Appendix A, Exhibit 1 – Initiating Events Screening questions. In answering “no” to “B. Transient initiators, ‘Did the finding cause a reactor trip and the loss of mitigation equipment relied upon to transition the plant from the onset of the trip to a stable shutdown condition?’”, the inspectors determined that the finding was of very low safety significance (Green).

The finding has a cross-cutting aspect in the area of problem identification and resolution associated with the corrective action program component, in that the licensee failed to thoroughly evaluate problems such that the resolution addressed the causes. Specifically, the licensee had identified in the past the reliability of the BOP inverter and static transfer switch as a cause for previous feedwater-related events but failed to implement recommended corrective actions to prevent future events (P.1(c)).

Enforcement: This finding does not involve enforcement action because no violation of a regulatory requirement was identified. The licensee entered this issue into the corrective action program as Condition Report 2013-00954. Because this finding does not involve a violation and is of very low safety significance, it is identified as a Finding. **(FIN 05000440/2013002-04, Failure to Perform Vendor Recommended Preventive Maintenance)**

.4 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 6-month period of July 1, 2012, through December 31, 2012, 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 a single semi-annual trend 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 (Closed) Licensee Event Report (LER) 05000440/2013-S01-00, Local Power Range Monitors Delivered to the Incorrect Address

a. Inspection Scope

On January 16, 2013, 34 local power range monitors (LPRMs) intended for delivery to Perry (FirstEnergy Nuclear Operating Company in Perry, Ohio) and containing a small quantity of radioactive material were delivered instead to a company called First Solar in

Perrysburg, Ohio. The licensee investigation revealed that the LPRMs were onsite at First Solar for approximately 1 hour and 40 minutes before the shipping company returned and took possession of them. The licensee made a 1-hour event notification to the NRC and documented the event and its corrective actions in CR 2013-00674. The licensee met with the shipping company to resolve identified deficiencies which led to delivery of the LPRMs to the incorrect location. This LER was reviewed by the inspectors and no additional findings or violations of NRC requirements were identified. The full apparent cause and corrective actions associated with this event are listed in the attachment. This LER is closed.

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

b. Findings

No findings were identified.

.2 (Closed) LER 05000/2013-001-00, Loss of Feedwater Results In Automatic Reactor Protection System Actuation

a. Inspection Scope

The inspectors reviewed the plant's response to the automatic reactor scram on January 22, 2013, following a loss of feedwater. See Section 4OA2.3 of this inspection report for a finding associated with an in-depth review of the root cause evaluation for this event. No additional findings were identified by the inspectors following review of this LER. Documents reviewed as part of this inspection 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.

b. Findings

No findings were identified.

.3 Control Room Operator Response to the January 22, 2013, Scram

The inspectors reported to the site and observed the licensee's response to the automatic scram on January 22, 2013. At the time of the scram, the plant was operating at 100 percent power. The operations crew on duty took appropriate actions for the conditions that existed at the time of the automatic scram and following the scram. The inspectors arrived on site shortly after the scram occurred and monitored the licensee's performance of recovery actions throughout the day in the control room and within the plant. The scram occurred at 3:22 a.m. and the plant entered cold shutdown at 8:36 p.m. Documents reviewed in this inspection are listed in the Attachment to this report.

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

a. Findings

No findings were identified.

4OA5 Other Activities

.1 Closed Temporary Instruction (TI)-2515/182 - Review of the Industry Initiative to Control Degradation of Underground Piping and Tanks

a. Inspection Scope

Leakage from buried and underground pipes has resulted in ground water contamination incidents with associated heightened NRC and public interest. The industry issued a guidance document, NEI 09-14, "Guideline for the Management of Buried Piping Integrity," to describe the goals and required actions (commitments made by the licensee) resulting from this underground piping and tank initiative. On December 31, 2010, NEI issued Revision 1 to NEI 09-14, "Guidance for the Management of Underground Piping and Tank Integrity," (ADAMS Accession No. ML110700122), with an expanded scope of components which included underground piping that was not in direct contact with the soil and underground tanks. On November 17, 2011, the NRC issued TI-2515/182 "Review of the Industry Initiative to Control Degradation of Underground Piping and Tanks" to gather information related to the industry's implementation of this initiative.

From February 4 – 6, 2013, the inspectors conducted a review of records and procedures related to the licensee's program for buried pipe, underground pipe, and tanks in accordance with Phase II of TI-2515/182. This review was done to confirm that the licensee's program contained attributes consistent with Sections 3.3 A and 3.3 B of NEI 09-14 and to confirm that these attributes were scheduled and/or completed by the NEI 09-14 Revision 1 deadlines. To determine if the program attribute was accomplished in a manner which reflected good or poor practices in program management, the inspectors interviewed licensee staff responsible for the buried pipe program and reviewed buried pipe program related documentation.

Based upon the scope of the review described above, Phase II of TI-2515/182 was completed.

b. Observations

The licensee's buried piping and underground piping and tanks program was inspected in accordance with Paragraph 03.02.a of the TI and it was confirmed that activities which correspond to completion dates specified in the program which have passed since the Phase I inspection was conducted, were completed. Additionally, the licensee's Buried Piping and Underground Piping and Tanks Program was inspected in accordance with Paragraph 03.02.b of the TI and responses to specific questions found in http://portal.nrc.gov/edo/nrr/dirs/irib/Inspection%20Manual%20Forms%20Templates%20Attachments/Forms/AllItems.aspx, was submitted to the NRC Headquarters staff.

c. Findings

No findings were identified.

.2 <u>(Closed) TI-2515/187 - Inspection of Near-Term Task Force Recommendation 2.3 Flooding Walkdowns</u>

a. Inspection Scope

The inspectors verified that licensee walkdown packages for external flooding and external wall penetrations of buildings related to safety, as well as internal building-to-building potential issues area, were reviewed as contained in the elements specified in NEI 12-07, Walkdown Guidance Document.

The inspectors accompanied the licensee on walkdowns of the Auxiliary Building and the Lake Erie protective barrier and verified that the licensee confirmed the following flood protection features:

- visual inspection of the flood protection feature was performed and external visual inspection for indications of degradation that would prevent its credited function from being performed was conducted when possible;
- critical structure's, system's, and component's dimensions were measured;
- available physical margin, where applicable, was determined; and
- flood protection feature functionality was determined using either visual observation or by review of other documents.

The inspectors independently performed their walkdown of several licensee-idenitified low margin items listed below and verified that the flood protection evaluations and planned corrective actions would be sufficient:

- Control Complex electrical penetration, 599’ level, designated as ECC2006;
- Fuel Handling Building electrical penetration, 599’ level, designated as EIB2050;
- West wall of EDG Building at ground level, 620’;
- Doorway to Unit 2 Auxiliary Building from Intermediate Building, 574' level, designated DIB0102; and
- East wall of Unit 1 Auxiliary Building at ground level, 620’, including door AX406.

The inspectors verified that noncompliances with current licensing requirements, and issues identified in accordance with the 10 CFR 50.54(f) letter, Item 2.g of Enclosure 4, were entered into the licensee’s CAP. In addition, issues identified in response to Item 2.g that could challenge risk-significant equipment and the licensee’s ability to mitigate the consequences will be subject to additional NRC evaluation.

b. Findings

No findings were identified.

4OA6 Meetings

.1 Quarterly Exit Meeting

On April 8, 2013, the inspectors presented the inspection results to the Site Vice-President, Mr. Vito Kaminskas, and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors verified that no proprietary information was retained by the inspectors or documented in this report.

.2 Interim Exit Meetings

Interim exits were conducted for:

- The Review of the Industry Initiative to Control Degradation of Underground Piping and Tanks (TI -2515/182) with Mr. Vito Kaminskas and other members of the licensee staff on February 6, 2013. The licensee confirmed that none of the potential report input discussed was considered proprietary.

- The results of the ISI inspection were reviewed with the Plant General Manager, Mr. John Grabnar, and other members of the licensee staff on March 28, 2013. 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.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

<u>Licensee</u>

V. Kaminskas, Site Vice-President
J. Grabnar, Site Operations Director
T. Veitch, Director, Regulatory Compliance
H. Hanson, Performance Improvement Director
D. Reeves, Site Engineering Director
J. Tufts, Operations Manager
J. Veglia, Maintenance Director

<u>NRC</u>

L. Kozak, Senior Reactor Analyst
M. Kunowski, Branch Chief

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

<u>Opened and Closed</u>

05000440/2013-002-01	NCV	Inadequate Procedure Resulted in Loss of High-Pressure Core Spray Function (Section 1R13)
05000440/2013-002-02	NCV	Valve Mis-position Causes SDV Level Detector Inoperability (Section 1R20)
05000440/2013-002-03	NCV	Failure to Follow Procedures for Conducting a Standby Liquid Control System Surveillance (Section 1R22)
05000440/2013-002-04	FIN	Failure to Perform Vendor Recommended Preventive Maintenance on the Balance-Of-Plant Static Transfer Switch (Section 4OA2.3)

<u>Closed</u>

05000440/2013-S01-00	LER	Local Power Range Monitors Delivered to the Incorrect Address (Section 4OA3.1)
05000440/2013-001-00	LER	Loss of Feedwater Results In Automatic Reactor Protection System Actuation (Section 4OA3.2)
2515/182	TI	Review of the Industry Initiative to Control Degradation of Underground Piping and Tanks (Section 4OA5.1)
2515/187	TI	Inspection of Near-Term Task Force Recommendation 2.3 Flooding Walkdowns (Section 4OA5.2)

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

- Perry Nuclear Power Plant Verification Walkdowns of Plant Flood Protection Features; dated November 12, 2012
- USAR Section 2.4.2.3; Effects of Local Intense Precipitation; Revision 12

1R04 Equipment Alignment

- VLI-C41; Valve Lineup Instruction – Standby Liquid Control System; Revision 8
- Drawing 302-0691-00000; Standby Liquid Control System; Revision W
- VLI-E12; Valve Lineup Instruction – Residual Heat Removal System; Revision 13
- ELI-R42; Electrical Lineup Instruction – DC Systems: Batteries Chargers Switchboards; Revision 8
- FPI-0CC; Pre-Fire Plan Instruction – Control Complex; Revision 9
- Drawing 206-0050-00000; Class 1E DC System – Div. 3; Revision Y
- Drawing 206-0051-00000; Class 1E DC System; Revision AAA
- Drawing 206-0052-00000; Non-Class 1E DC System Bus D1A & D1B; Revision DDD
- Drawing 302-0621-00000; Emergency Closed Cooling System; Revision SS
- Drawing 302-0705-00000; Low Pressure Core Spray System; Revision FF
- SOI-E21; Low Pressure Core Spray System; Revision 28
- CR 2012-13151; Drive Pin Size Needs Evaluated for LPCS Min Flow Valve; dated August 27, 2012
- CR 2013-02487; Momentary LPCS Discharge Pressure Low Alarm on RHR A Pump Start; dated February 19, 2013
- CR 2013-02309; QC Fit-up Inspection Not Performed Prior to Weld Out; dated February 14, 2013
- ARI-H13-P601-0021-G6; LPCS Pump Discharge Press Lo; Revision 15
- CR 2013-00114; Water Overflow From SLC Test Tank During Water Sample Due to Valve Misposition, dated January 3, 2013

1R05 Fire Protection

- FPI-1DG; Pre-Fire Plan Instruction - Diesel Generator Building; Revision 6
- FPI-0CC; Pre-Fire Plan Instruction – Control Complex; Revision 9
- FPI-0IB; Pre-Fire Plan Instruction – Intermediate Building; Revision 7
- FPI-1AB; Pre-Fire Plan Instruction – Auxiliary Building Unit 1; Revision 3

1R08 Inservice Inspection Activities

- CR 2013-00767, Documentation of NDE UT Equipment Annual Inventory Verification Not Maintained; dated January 13, 2013
- CR 2013-00159, Boron Crystalline Formations Identified During ISI; dated January 4, 2013

- CR G202-2011-95050, Condition Monitoring Exams for Steam Dryer Upper Support Ring Indications; dated May 18, 2011
- CR-2013-04625, Rework Required for Weld Prep on 1E12-0390 Found Prior to ISI Exam, READE Tool Used; dated March 27, 2013
- NQI-1042, Visual Examination; Revision 16
- NQI-0942, Magnetic Particle Examination; Revision 17
- NQI-0954, Appendix VIII Procedure for The Examination of Ferritic Pipe Welds; Revision 2
- Welding Procedure Specification, 1.1.2-001; Revision 12
- Weld History Record (Single Joint), Work Order 200389452; dated May 14, 2011
- Drawing 304-0631-00103, Reactor Core Isolation Cooling; Revision D
- Drawing Update Notice 02-0357-001-001, Reactor Core Isolation Cooling; Revision 2

1R11 Licensed Operator Requalification Program

- Simulator Exercise Guide OTLC-3058201301_PY-SGC2; Cycle 1 2013 Evaluated Scenario C2; Revision 0; dated December 20, 2012
- IOI-0003; Power Changes; Revision 48
- IOI-0005; Maintaining Hot Shutdown; Revision 14
- EOP-01; RPV Control; Revision 3
- EOP-01 Chart; Chart-RPV Control; Revision D
- CR 2013-01022; Post-Scram Event Operating Crew Critique from the Loss of Feedwater Scram per NOBP-TR-1122

1R12 Maintenance Effectiveness

- Notification # 600802864; IRM 'B' Monitor; dated December 22, 2012
- WO 200541571; IRM 'B' Monitor; dated January 23, 2013
- ICI-C-C51-12; Intermediate Range Monitor (IRM) Channel Calibration/Adjustment; Revision 2
- SVI-C51-T0023-B; IRM B Neutron Flux Trips Channel Calibration for 1C51-K601B; dated January 23, 2013
- Notification #600687056; Suppression Pool Level Channel Check/CR11-95634; dated June 2, 2011
- WO200552188; Mechanically Agitate Check Valve 1G43F0508A; dated March 7, 2013
- WO200552185; MOV Static Testing of 1G43F0030A; Scheduled for RFO-14
- System G43 Suppression Pool Makeup – System Health Report 2012-4; dated February 7, 2013
- CR 2013-04152; 1G43F0030A Limit Switch Adjustment Results Are Inconclusive Relative to Leakage and CR 2013-01421 POD Intent; dated March 21, 2013
- CR 2010-70252; SVI-G43-T0405; Procedure Enhancements; dated January 19, 2010
- CR 2013-01421; Check Valve Failed Leakage Requirement for SVI-G43-T2003; dated January 30, 2013
- CR 2010-76908; Foreign Material Entered Suppression Pool Make-up Line Bravo; dated May 15, 2010
- CR 2011-95634; Suppression Pool Level Channel Check Unsat; dated May 29, 2011
- CR 2013-04089; Automatic Opening of HPCS Suppression Pool Suction Valve During LLRT Testing; dated March 20, 2013

1R13 Maintenance Risk Assessments and Emergent Work Control

- Weekly Risk Analysis for RHR 'A' Decon During Week of February 11, 2013

- Orange Maintenance Risk for Greater Than 50 Percent of LCO Outage Time for RHR 'A' Decon
- WO 200433421; ESW Pump 'A' Discharge Valve Maintenance; dated February 26, 2013
- NOP-OP-1007; Risk Management; Revision 16
- NOP-OP-1005; Shutdown Defense in Depth; Revision 13
- Management Alignment and Ownership Meeting Packet – Monday – February 25, 2013
- Perry Nuclear Power Plant – Perry Work Implementation Schedule, Week 10, Period 7, Division 1, From 1200 Tuesday, 02/26/13 to 1200 Wednesday, 02/27/13
- Radiation Work Permit 130165; Chemical Decontamination of RHR 'A' System, Resin and Filter Transfer Activities – Work to Include Walkdowns / Inspections, Resin and Filter Transfer to Storage Areas in the Radwaste Building, RP / Decon Support, and Operations Activities; Revision 0; dated February 22, 2013
- Radiation Work Permit 130165; Chemical Decontamination of RHR 'A' System, Resin and Filter Transfer Activities – Work to Include Walkdowns / Inspections, Resin and Filter Transfer to Storage Areas in the Radwaste Building, RP / Decon Support, and Operations Activities; Revision 1; dated March 2, 2013
- ALARA Plan # 130165; Chemical Decontamination of RHR 'A' System, Resin and Filter Transfer Activities – Work to Include Walkdowns / Inspections, Resin and Filter Transfer to Storage Areas in the Radwaste Building, RP / Decon Support, and Operations Activities; Revision 0; dated February 22, 2013
- ALARA Plan # 130165; Chemical Decontamination of RHR 'A' System, Resin and Filter Transfer Activities – Work to Include Walkdowns / Inspections, Resin and Filter Transfer to Storage Areas in the Radwaste Building, RP / Decon Support, and Operations Activities; Revision 1; dated March 2, 2013
- MRS-SSP-2857-GPRY1; Perry Chemical Decontamination Resin Transfer Procedure; Revision 2
- WO 2005455539; HPCS ECCS Integrated Test; dated March 15, 2013
- SVI-E22-T2680; HPCS ECCS Integrated Test; Revision 1
- SVI-E22-T2680; HPCS ECCS Integrated Test; Revision 2
- CR 2013-03863; Loss of EH13 Bus During Initial Performance of SVI-E22-T2680; dated March 14, 2013
- CR 2013-03781; HPCS DG Failed to Energize EH13 During SVI-E22-T2680 HPCS ECCS Integrated Test; dated March 14, 2013
- CR 2013-03823; Bus EH13 Breaker Trip Alarm Was Received When the Division 3 Preferred Source Breaker Was Opened During Paralleling Operations; dated March 15, 2013

<u>1R15 Operability Determinations and Functionality Assessments</u>

- SVI-B21-T1176; RCS Heatup and Cooldown Surveillance; Revision 12
- CR 2013-00945; Unexpected TS Entry Into 3.r.11; dated January 22, 2013
- Drawing 248A9035P010; Thermocouple; dated September 14, 1977
- Drawing 248A9036; Thermocouple; dated September 14, 1977
- Drawing 304-0601-00102; Piping Isometric Reactor Recirculation Valve Flow Control System – Reactor Building; Revision B
- Drawing 302-0606-00000; Nuclear Boiler System; Revision EE
- Drawing 163C1258; Temperature Element; dated May 7, 1992
- Drawing 208-0010-00003; Nuclear Boiler System – Vessel Temperature Monitoring; Revision S
- ODMI from CR 2013-01127; Plant Operations with DB-1-A, Non-Essential Vital Power Inverter, Not In-Service; Revision 0

- CR 2013-00958; During Walkdown Post-Scram Found MCC F1D08 on Alternate Source; dated January 22, 2013
- CR 2013-00954; The DB1A Inverter Trouble Alarm Came In on The Reactor Scram Today and Stayed Locked In; dated January 22, 2013
- CR 2013-01011; Inverter 1R14S0004 Was Found on Its Alternate Source and With the Fail Light on Following Reactor Scram; dated January 22, 2013
- CR 2013-00122; Degraded Circuit Card; dated January 4, 2013
- CR 2013-00274; Unexpected Division 2 DG Alarms Due to Failed Annunciator Module; dated January 8, 2013
- CR 2013-00114; Water Overflow from SLC Test Tank During Water Sample Due to Valve Mis-position; dated January 3, 2013
- CR 2013-00145; Post Event Debrief for ONI-ZZZ-5 Entry Due to Spill in the Containment and ONI-C11-1 Entry Due to Inability to Move Control Rods; dated January 4, 2013
- CR 2013-02081; Approved Calculation Does Not Exist for a Helicoil-Threaded Insert Repair of The Dikkers SRV Inlet Flange; dated February 11, 2013
- Calculation SQ-0046, Addendum A-01, Revision 1 for Quantity and Thread Engagement Requirements for Helicoil Repairs to SRV Inlet and Outlet Flanges; dated February 15, 2013
- Prompt Functionality Assessment from CR 2013-02744 for Being Unable to Isolate Nuclear Closed Cooling to the 'A' Fuel Pool Heat Exchanger; Revision 0
- eSOMS Narrative Logs; February 25, 28, and March 4, 2013

1R18 Plant Modifications

- ECP 12-0488-001; Temporary Modification to Support Chemical Decon Activities Prior to and Through RFO14, Raise the Alarm Switch to Allow Passage Under Door 1L54E0005 (AX-404); Revision 0
- WO 200492595; PY-1L54 Rolling Steel Door Operators; dated December 20, 2012
- WO 200338572; PY-E12 Residual Heat Removal; dated March 24, 2013

1R19 Post-Maintenance Testing

- WO 200481465; Replace LVL Instrument Reference Leg Vent Valve; dated February 6, 2013
- WO 200430918; Replace Standby Liquid Control Storage Tank Level Instrument Vent Valve; dated February 6, 2013
- SVI-E12-T2001; RHR A Pump and Valve Operability Test; Revision 30; dated February 19, 2013
- WO 200338572; Residual Heat Removal RHR 'A' Decon; dated February 19, 2013
- SOI-E12; Residual Heat Removal; Revision 58
- OAI-0201; Operations General Instructions and Operating Practices; Revision 32
- SVI-E51-T1269; RCIC System Valve and Flow Controller Position Verification; Revision 12
- SOI P45/49; Emergency Service Water and Screen Wash System; Revision 21
- SOI E51; Reactor Core Isolation Cooling; Revision 30
- CR 2013-01898; Degraded Input Voltage to Controller; dated February 7, 2013
- WO 200438859; Perform a Calibration Check of Remote Shutdown RCIC Flow Controller; dated January 29, 2013
- CR 2013-01542; RCIC Flow Controller for Remote Shutdown Panel; dated January 31, 2013
- ICI-C-E51-0004; RCIC NUS Type 701 Controller; Revision 0
- CR 2013-01527; RCIC NUS Type 701 Controller Procedure Inconsistencies; dated January 31, 2013

1R20 Refueling and Other Outage Activities

- CR 2011-03864; NRC Question On Tech Spec 3.4.11 RCS Pressure and Temperature Curves / Drawing A Vacuum During Non-Nuclear Heatup; dated October 17, 2011
- CR 2013-00945; Unexpected TS Entry Into 3.4.11; dated January 22, 2013
- CR 2013-01010; Cyber Security Event Analysis; dated January 22, 2013
- CR 2013-01011; Inverter 1R14S0004 Was Found on Its Alternate Source and With The Fail Light on Following Reactor Scram; dated January 22, 2013
- CR 2013-01022; Post Scram Event Operating Crew Critique from the Loss of Feedwater Scram per NOBP-TR-1122; dated January 22, 2013
- CR 2013-01080; Reactor Bottom Head Temperature Rise Following Restoration of Flow Through the Vessel; dated January 24, 2013
- CR 2013-01136; Control 30-27 Not Settling; dated January 24, 2013
- CR 2013-01151; ESW Pump 'B' Has Excessive Packing Leakage; dated January 25, 2013
- CR 2013-01152; Inadequate PM On Internal Cards for Static Transfer Switch; dated January 25, 2013
- CR 2013-01154; Control Rod 46-51 Not Settling; dated January 24, 2013
- CR 2013-01213; Reverse Flow Through the Offgas System Caused by the Condenser Air Removal System; dated January 22, 2013
- CR 2013-01215; RWCU Flow Instrument Had Air Sucked Into the Instrument During Venting Operations; dated January 25, 2013
- CR 2013-01254; Delays in Start Up Due to SJAE Inlet Temperature Requirements; dated January 27, 2013
- CR 2013-01258; Hissing Noise from Packing of MSIV Bypass Valve for Main Steam Line Warmup (PY-1B21F0020); dated January 27, 2013
- CR 2013-01821; Tripped/Missing Accelerometers on New Fuel Receipt Shipment; dated February 5, 2013
- Post Scram Restart Report Perry Nuclear Power Plant; Scram Number 1-13-01 on January 22, 2012 at 0332 Hours; dated January 25, 2013
- IOI-0001; Cold Startup; Revision 36
- IOI-0003; Power Changes; Revision 48
- IOI-0005; Maintaining Hot Shutdown; Revision 14
- IOI-0012; Maintaining Cold Shutdown; Revision 14
- IOI-0015; Seasonal Variations; Revision 20
- Perry Nuclear Power Plant Work Implementation Schedule – Reactor Low Level Forced Outage; dated January 23 through January 26, 2013
- Notification # 600808918; January 2013 Forced Outage PY-1FOAC06 Restart Readiness; dated January 25, 2013
- Event Notification; Automatic Reactor Protection System Actuation; dated January 22, 2013
- FTI-E0023; Channeled New Fuel Receipt and Storage; Revision 6
- Fatigue Assessment – Summary from January 22, 2013 to January 27, 2013
- CR 2013-01468; EER for Control Rod 26-31 RC&IS Position Indicator Probe Jumper May Require Further Evaluation/Documentation for Use of Exception in NOP-CC-2003; dated January 30, 2013
- PTI-E12-P0012A; RHR Loop A Shutdown Cooling Interlock Testing; Revision 1
- CR 2013-04123; Unable to Complete SVI-C51-T0022D due to IRM ‘D’ Upscale Trip Locked in at P680; dated March 20, 2013
- CR 2013-04447; Elevated Airborne Activity in Containment Following RPV Steam Separator Removal; dated March 25, 2013

- NOBP-LP-2603; Event-Free Tools and Verification Practices; Revision 6
- NOBP-LP-2601; Human Performance Program; Revision 7
- NORM-LP-2006; Human Performance Handbook; Revision 5
- NOP-WM-4006; Conduct of Maintenance; Revision 5
- NOBP-OP-1014; Component Control Program; Revision 1
- NOP-OP-1001; Clearance/Tagging Program; Revision 19
- CR 2013-04452; Misposition of PY-C11F0158A; dated March 25, 2013
- CR 2013-04435; Valve Found Out of Position; dated March 25, 2013
- CR 2013-03914; RPS Inst Vol Hi Level Alarm Locked In; dated March 18, 2013
- CR Reportability Review for CR 2013-04435; dated March 26, 2013
- Full Apparent Cause Review for CR 2013-04435; dated April 24, 2013

1R22 Surveillance Testing

- SVI-E21-T2001; Low-Pressure Core Spray Pump and Valve Operability Test; Revision 24
- SVI-E51-T2001; RCIC Pump and Valve Operability Test; Revision 36
- SOI E51; Reactor Core Isolation Cooling System; Revision 30
- SOI P45/49; Emergency Service Water and Screen Wash System; Revision 21
- SVI-C41-T2001B; Standby Liquid Control 'B' Pump and Valve Operability Test; Revision 17
- CR 2013-01131; RCIC Sight Glass Oil Leak; dated January 24, 2013
- CR 2013-01233; RCIC Turbine Oil Flow Indicator Leaking; dated January 26, 2013
- SVI-E12-T0146; ECCS/LPCI Pump ‘A’ Start Time Delay Relay Channel Functional/Calibration for 1E12A-K70A; Revision 9
- WO 200455380; ECCS LPCI Pump ‘A’ Start Time Delay Relay Channel Functional/Calibration for 1E12A-K70A; dated February 28, 2013
- SVI-M51-T2003-A; Combustible Gas Mixing System ‘A’ Operability Test; Revision 8
- WO 200455543; Combustible Gas Mixing System ‘A’ Operability Test; dated March 1, 2013
- SVI-B33-T0257-B; EOC-RPT Breaker Arc Suppression Response Time for 1B33A-CB4A and 1B33A-CB4B; Revision 5

1EP6 Drill Evaluation

- Simulator Exercise Guide OTLC-3058201301_PY-SGC2; Cycle 1 2013 Evaluated Scenario C2; Revision 0; dated December 20, 2012
- NOBP-TR-1112; FENOC Conduct of Simulator Training and Evaluation; Revision 2

4OA1 Performance Indicators

- NOBP-LP-4012; NRC Performance Indicators; Revision 04
- NOBP-LP-4012-01; NRC Performance Indicator Data Sheets; Unplanned Reactor Scrams per 7,000 Critical Hours; January 2012 through December 2012; Revision 02
- NOBP-LP-4012-02; NRC Performance Indicator Data Sheets; Unplanned Scrams with Complications (USwC); January 2012 through December 2012; Revision 03
- NOBP-LP-4012-03; NRC Performance Indicator Data Sheets; Unplanned Power Changes per 7,000 Critical Hours; January 2012 through December 2012; Revision 02

4OA2 Identification and Resolution of Problems

- CR 2012-10597; Maintenance Rule Unavailable Hours for Diesel Fire Pump; dated July 3, 2012
- CR 2012-10626; Inadvertent Sounding of Perry Emergency Sirens; dated July 3, 2012
- CR 2012-10972; Fire Wrap Modification May Challenge MSO Required Resolution for NRC Compliance November 2, 2012; dated July 12, 2012
- CR 2012-11041; CNRB Concern – Sustainability of Risk Management Actions; dated July 13, 2012
- CR 2012-11113; Adverse Condition Was Not Identified in a Timely Manner; dated July 16, 2012
- CR 2012-11207; USAR Time Critical Operator Action Validation Suppression Pool Cooling Actions; dated July 18, 2012
- CR 2012-11569; Two Improvement Opportunities from an Independent Assessment of Radiation Protection Safety Culture Were Not Directly Addressed by Corrective Actions Assigned to CR-2012-08436; dated July 25, 2012

- CR 2012-11580; FENOC Placekeeping Requirements for Steps Which Have Initial Blocks is Different Than the INPO Guidance; dated July 25, 2012
- CR 2012-11895; Convertor Operating Outside Normal Range; dated July 31, 2012
- CR 2012-12000; UN2910 (Low Level Radioactive) Shipment Received Without Proper Notification; dated August 2, 2012
- CR 2012-12030; Perry Has a Significantly Higher Number of Temporary Modifications Installed Compared To the Other Two FENOC Sites; dated August 3, 2012
- CR 2012-12169; Benchmarking Not Completed; dated August 7, 2012
- CR 2012-12174; Snapshot Self-Assessment Overdue; dated August 7, 2012
- CR 2012-12227; Potential Trend in Too High a Threshold for Condition Report Generation; dated August 7, 2012
- CR 2012-12252; Cognitive Trend Identified with the Unavailability of M&TE When Needed for a Scheduled Surveillances (sic); dated August 8, 2012
- CR 2012-12373; Possible Undocumented Modification Installed in the Plant; dated August 10, 2012
- CR 2012-12479; 50.54f Seismic Walkdown ALARA Practices; dated August 13, 2012
- CR 2012-12591; Suspect Results Obtained During Analysis of the Division 2 Fuel Oil Storage Tank Sample; dated August 10, 2012
- CR 2012-12791; Temporary Modification 12-0507-001 for Radwaste Elevation 574' Recovery Installed Without Notification to Document Control of Implementation; dated August 20, 2012
- CR 2012-12866; Unexpected Alarm, H13-P680-0005-D8, Inhibit Rod Motion RCIS OOS in and Reset; dated August 21, 2012
- CR 2012-13232; NRC ID 2012 95002: Potential Incomplete Information Communicated to NRC; dated August 28, 2012
- CR 2012-13482; Radiation Protection “Stop Work Authority” Exercised for Radwaste 574’ Resin Spill; dated August 31, 2012
- CR 2012-13556; Rx (Reactivity) Mgt (Management) Committee – Potential Low Level Trend with LPRM Failure Rates; dated September 4, 2012
- CR 2012-13792; Diesel Fuel BP Diesel Supreme Being Dis-Continued; dated September 8, 2012
- CR 2012-13865; NRC ID 2012 95002: CRB Closure Package 2011-1593-79 Sustainability Issue; dated September 10, 2012
- CR 2012-14075; Trigger Point to Revise ODMI for Fuel Pool Cooling and Cleanup System F/D Isolation Valves was Reached on 12/27/11 and Revision Has Not Been Completed; dated September 13, 2012
- CR 2012-14385; Mis-identified SVI in MSPI Basis Document; dated September 19, 2012
- CR 2012-14532; Diesel Fuel Oil Particulate Samples Not Dried in Accordance with ASTM 2276-88 and Technical Specification Bases 3.8.3.3; dated September 21, 2012
- CR 2012-14541; M&TE Declared Lost on CR#2012-14404 Has Been Found and Returned; dated September 21, 2012
- CR 2012-14559; ADHR Calculations Do Not Identify Minimum Required Service Water Flow to the ADHR Heat Exchanger; dated September 21, 2012
- CR 2012-14606; Precursor Error During Performance of SVI; dated September 21, 2012
- CR 2012-14657; Condition Report 2012-09447 (Root Cause) Was Presented to the CARB on 9/22/2012 and Was Rejected; dated September 24, 2012
- CR 2012-14817; Failure to Perform Heat Exchanger Testing as Required by Commitment L01916 to NRC Generic Letter (GL) 89-13; dated September 25, 2012
- CR 2012-14936; USAR Wording Conflicts with ONI-SPI for Use of Division 1 DG non-LOCA Trip B/P Switch; dated September 26, 2012

- CR 2012-15078; NRC ID 2012 95002: Professional Difference of Opinion Resolution – Ability to Climb Scaffolding; dated September 27, 2012
- CR 2012-15454; Broken Phenolic Piece from Control Device Found During Inspection; dated October 3, 2012
- CR 2012-15618; Reactor Operator Took Valve Switch on an Open Valve to the Open Position Instead of in the Closed Direction as He Intended; dated October 4, 2012
- CR 2012-16086; Outage Scope Change Request Removes the Replacement of the Feedwater Venturi Flanges from RFO14 Scope; dated October 11, 2012
- CR 2012-16307; SVI-M51T0321A Failed and Terminated During Gas Checks; dated October 15, 2012
- CR 2012-16821; Degraded Containment Coatings; dated October 24, 2012
- CR 2012-17025; Loss of Plant Computer ICSU1M and ERDS; dated October 28, 2012
- CR 2012-17053; Multiple Spurious Operation (MSO) Concern will not be Resolved by the end of the Enforcement Discretion Period; dated October 29, 2012
- CR 2012-17317; Change in NEIL Standards Regarding Trash Receptacles in the Area; dated November 1, 2012

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

- LER 05000440/2013-001-00; Loss of Feedwater Results in Automatic Reactor Protection System Actuation; dated March 21, 2013
- LER 05000440/2013-S01-00; Local Power Range Monitors Delivered to the Incorrect Address; dated March 15, 2013
- CR 2013-00674; Local Power Range Monitors Not Delivered to Perry; dated January 16, 2013
- CR 2013-00924; Rod Control and Information System Lockup; dated January 22, 2013
- CR 2013-01011; Inverter 1R14S0004 Was Found on Its Alternate Source and with the Fail Light on Following Reactor Scram; dated January 22, 2013
- CR 2013-01004; Automatic Reactor Scram Occurred at 03:32 01/22/2013 Post Scram Report; dated January 22, 2013
- CR 2013-00948; IRM D Failure with IRM B Already Failed Caused the Control Room to NOT Be Able to Reset the 1/2 Scram on the Plant Scram Today; dated January 22, 2013
- CR 2013-00952; Two of the Four Central De-Ice Valves Would Not Close On the Cooling Tower When Directed by SOI-N71 for Cold Weather Operations; dated January 22, 2013
- CR 2013-00953; Cooling Tower Bypass Valves Could Not Be Opened to Place the Cooling Tower in Bypass Operations; dated January 22,2013
- CR 2013-00954; The DB1A Inverter Trouble Alarm Came in on the Reactor Scram Today and Stayed Locked In; dated January 22, 2013
- CR 2013-0957; Voltage and Load Fluctuations Noted on the M51 Hydrogen Recombiner About 20 Minutes Before the Total Loss of Feedwater and Reactor Scram; dated January 22, 2013
- CR 2013-0959; Rod Control System Locked Up a Few Hours Before the Power Supply Issue and Loss of Feedwater Scram; dated January 22, 2013
- CR 2013-0961; Hot Surge Tank Level Controller Stuck at 20 Percent Open in AUTO with Hot Surge Tank Overflowing Following Reactor Scram; dated January 22, 2013
- CR 2013-0962; Full Core Display Showed RED and GREEN Indications Initially in the Reactor Scram; dated January 22, 2013
- CR 2013-0964; Control Rod 26-31 Showed DUAL Full in Indication on the Reactor Scram Today; dated January 2, 2013
- CR 2013-00968; Unable to LATCH Drain Valves Using the Pressure Control Hard Card During the Reactor Scram Actions; dated January 22, 2013

- CR 2013-00972; RFBP Min Flow Valve 1N27-F305 Failed to AUTO Open on the Scram Today (REPEAT ISSUE); dated January 22, 2013
- CR 2013-00974; Control Room SPDS and Digital Feedwater Screens Lost Power During the Reactor Scram; dated January22, 2013
- CR 2013-00977; Steam Jet Air Ejector Suction Valve 1N62-F170A Failed to Close Causing Significant Air Flow in OFF GAS (REPEAT ISSUE); dated January 22, 2013

<u>4OA5 Other Activities</u>

- 3203.100-01; Perry Nuclear Power Plant Buried Piping Program Basis Document; Revision 0
- 033202-01; Perry Nuclear Plant Unit 1 ESW Piping Susceptibility Evaluation; Revision 1
- 033202-02; Perry Nuclear Plant Inspection Plan; Revision 0
- 3203.100-01; Attachment E; Electronic Markup of Plant Drawings; Revision 0
- NOP-ER-2007; Underground Piping and Tanks Integrity Program; Revision 4
- NOP-ER-2101; Engineering Program Management; Revision 7
- PTI-P45-P0003; ESW System Loop C Flow And Differential Pressure Test; Revision 12
- NOP-OP-2012; Groundwater Monitoring; Revision 6
- NOP-OP-4705; Response to Contaminated Spills/Leaks; Revision 6
- NORM-ER-3113; Cathodic Protection; Revision 2
- NOP-WM-4007; Excavation & Trenching Controls; Revision 2
- NOP-CC-2003; Engineering Changes; Revision 17
- ISI-R45-T1100-3; Division 1 Standby Diesel Generator Fuel Oil Functional Pressure Test – Class 3; Revision 4
- SVI-R45-T2001; Division 1 Diesel Generator Fuel Oil Transfer Pump and Valve and Starting Air Check Valve Operability Test; Revision 19
- ISS-2000; Piping and Mechanical Equipment Installation; Revision 9
- P.O. No. 55111120; Cathodic Protection System Annual Survey Report for the Perry Nuclear Power Plant; dated January 2012
- Final Report v.1.0; Long Range Guided Wave Inspection Report – Perry Station Guided Wave Examination; dated August 10, 2009
- CR-2012-00803; Underground Piping and Tanks Integrity Initiative Milestone Tracking; dated January 17, 2012
- 2012-3; Quarterly System Health Report; Cathodic Protection
- FO-SA-2012-0008; 2012 Buried Pipe Program Focused Self-Assessment; dated September 3, 2012
- SN=SA-10-147; Snapshot Self-Assessment Buried Pipe Integrity Program (BPIP); dated April 20, 2010
- BOP-UT-09-255; UT Erosion /Corrosion Examination; dated October 7, 2009
- BOP-UT-09-257; UT Erosion /Corrosion Examination; dated October 7, 2009
- BOP-UT-09-258; UT Erosion /Corrosion Examination; dated October 7, 2009

<u>4OA5 Other Activities (Temporary Instruction 2515/187)</u>

- Perry Nuclear Power Plant Verification Walkdowns of Plant Flood Protection Features; dated November 20, 2012
- CR 2012-17869; USAR Clarification Needed, Identified During External Flooding Walkdowns for NRC 10CFR50.54f Letter; dated November 12, 2012
- CR 2012-17867; Additional Evaluation is Needed for External Flooding Effects to Support External Flooding Walkdowns for NRC 10CFR50.54f Letter; dated November 12, 2012

- FENOC Response to NRC Request for Information Pursuant to 10CFR50.54(f) Regarding the Flooding Aspects of Recommendation 2.3 of the Near-Term Task Force Review of Insights from the Fukushima Dai-ichi Accident; dated November 27, 2012
- CR 2011-01898; Review of Site Flooding Due to Recent Changes in the Yard; dated September 14, 2011
- CR 2012-17308; Unsealed Conduits in IB 599', Identified During External Flooding Walkdowns for NRC 10CFR50.54f Letter; dated November 1, 2012
- CR 2012-17301; Potential Unit 2 Aux Bldg Flooding Identified During External Flooding Walkdowns for NRC 10CFR50.54f Letter; dated November 1, 2012
- CR 2012-17314; Unsealed Conduits in CC 599', Identified during External Flooding Walkdowns for NRC 10CFR50.54f Letter; dated November 1, 2012
- CR 2012-17305; Potential Unqualified Seal, Identified During External Flooding Walkdowns for NRC 10CFR50.54f Letter; dated November 1, 2012
- CR 2012-17868; The Site PMP (Probable Maximum Precipitation) Event Evaluation Requires Updating, Identified During External Flooding Walkdowns for NRC 10CFR50.54f Letter; dated November 12, 2012
- CR 2009-68678; A One-Inch Delta Exists Between the FHB Benchmark and External Monuments; dated December 7, 2009
- CR 2012-17687; Additional Evaluation Is Needed for External Flooding Effects to Support Identified External Flooding Walkdowns for NRC 10CFR50.54f Letter; dated November 12, 2012
- CR 2012-19384; Apparent USAR Discrepancy; dated December 26, 2012
- External Flooding Walkdown Record Form for East Wall of Auxiliary Bldg; dated August 29, 2012
- External Flooding Walkdown Record Form for DIB 0102; dated August 21, 2012
- External Flooding Walkdown Record Form for DG West Wall and Access; dated August 29, 2012
- External Flooding Walkdown Record Form for EIB 2082; dated September 11, 2012
- External Flooding Walkdown Record Form for EIB 2050; dated August 21, 2012
- External Flooding Walkdown Record Form for ECC 2006; dated August 21, 2012

LIST OF ACRONYMS USED

ADAMS	Agencywide Document Access Management System
ASME	American Society of Mechanical Engineers
ATC	At-the-Controls
BOP	Balance-of-Plant
CAP	Corrective Action Program
CR	Condition Report
CFR	Code of Federal Regulations
DG	Diesel Generator
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
HPCS	High-Pressure Core Spray
IMC	Inspection Manual Chapter
I&C	Instrumentation and Controls
IP	Inspection Procedure
IR	Inspection Report
ISI	Inservice Inspection
LER	Licensee Event Report
LOOP	Loss of Offsite Power
LPCS	Low-Pressure Core Spray
LPRM	Local Power Range Monitor
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NLO	Non-Licensed Operator
NRC	Nuclear Regulatory Commission
OSP	Outage Safety Plan
ONI	Off-Normal Instruction
PI	Performance Indicator
RCIC	Reactor Core Isolation Cooling
RCIS	Rod Control and Information System
RFO	Refueling Outage
RHR	Residual Heat Removal
RPV	Reactor Pressure Vessel
SDP	Significance Determination Process
SDV	Scram Discharge Volume
SLC	Standby Liquid Control
SPAR	Standardized Plant Analysis Risk
SRA	Senior Reactor Analyst
SVI	Surveillance Instruction
TI	Temporary Instruction
TS	Technical Specification
USAR	Updated Safety Analysis Report
UT	Ultrasonic Examination
Vdc	Volts direct current
WO	Work Order

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 Agencywide Document Access and Management System (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Michael Kunowski, Chief
Branch 5
Division of Reactor Projects

Docket No. 05000440
License No. NPF-58

Enclosure: Inspection Report 05000440/2013002
w/Attachment: Supplemental Information

cc w/encl: Distribution via ListServ™

DISTRIBUTION:
See next page

DOCUMENT NAME: Perry IR 2013 002
☐ Publicly Available ☐ Non-Publicly Available ☐ Sensitive ☐ Non-Sensitive
To receive a copy of this document, indicate in the concurrence box "C" = Copy without attach/encl "E" = Copy with attach/encl "N" = No copy

OFFICE	RIII		RIII		RIII		RIII	
NAME	MKunowski:rj							
DATE	05/10/13							

OFFICIAL RECORD COPY

Letter to V. Kaminskas from M. Kunowski dated May 10, 2013

SUBJECT: PERRY NUCLEAR POWER PLANT - NRC INTEGRATED INSPECTION REPORT 05000440/2013002

DISTRIBUTION:
Doug Huyck
RidsNrrPMPerry Resource
RidsNrrDorlLpl3-2 Resource
RidsNrrDirsIrib Resource
Chuck Casto
Cynthia Pederson
Steven Orth
Allan Barker
Christine Lipa
Carole Ariano
Linda Linn
DRPIII
DRSIII
Patricia Buckley
Tammy Tomczak
ROPreports.Resource@nrc.gov