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

February 6, 2012

Vito A. Kaminskas, Site Vice President
FirstEnergy Nuclear Operating Company
Perry Nuclear Power Plant
P. O. Box 97, 10 Center Road, A-PY-290
Perry, OH 44081-0097

SUBJECT: PERRY NUCLEAR POWER PLANT - NRC INTEGRATED INSPECTION REPORT 05000440/2011005 (DRP) AND 07200069/2010001 (DNMS)

Dear Mr. Kaminskas:

On December 31, 2011, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Perry Nuclear Power Plant Unit 1. The enclosed inspection report documents the inspection results which were discussed on January 12, 2012, 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 NRC-identified findings of very low safety significance (Green) were identified during this inspection.

All four of these findings were determined to involve violations of NRC requirements. Additionally, the NRC determined that a traditional enforcement Severity Level IV violation occurred. This traditional enforcement violation was indentified with an associated finding evaluated as very low safety significance (Green). Further, a licensee-identified violation which was determined to be of very low safety significance is listed in this report. The NRC is treating all of the findings 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 Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies to the Regional Administrator, Region III, the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the Resident Inspector 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 (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/

John B. Giessner, Chief
Branch 4
Division of Reactor Projects

Docket No. 50-440; 72-069
License No. NPF-58

Enclosure: Inspection Report 05000440/2011005 and 07200069/2010001
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-440 and 72-069
License No:	NPF-58
Report No:	05000440/2011005 and 07200069/2010001
Licensee:	FirstEnergy Nuclear Operating Company (FENOC)
Facility:	Perry Nuclear Power Plant, Unit 1
Location:	Perry, Ohio
Dates:	October 1, 2011, through December 31, 2011
Inspectors:	M. Marshfield, Senior Resident Inspector T. Hartman, Resident Inspector J. Beavers, Emergency Preparedness Inspector M. Bielby, Senior Operations Engineer J. Bozga, Reactor Inspector R. Edwards, Reactor Inspector D. Hoang, Structural Engineer L. Jones, Reactor Engineer R. Langstaff, Senior Reactor Inspector V. Meghani, Reactor Inspector
Approved by:	John B. Giessner, Chief Branch 4 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

Inspection Report (IR) 05000440/2011005 and IR 07200069/2010001; 10/01/2011 – 12/31/2011; Operability Determinations and Functionality Assessments; Surveillance Testing; Other Activities.

This report covers a 3-month period of inspection by resident inspectors and announced baseline inspections by regional and headquarters inspectors. The inspectors identified four Green findings and one Severity Level IV violation. 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) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP); the cross-cutting aspects were determined using IMC 0310, "Components Within the Cross-Cutting Areas." Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," (ROP) Revision 4, dated December 2006.

A. NRC-Identified and Self-Revealed Findings

Cornerstone: Initiating Events

- Severity Level IV. The inspectors identified a finding of very low safety significance and an associated Severity Level IV NCV of Technical Specification (TS) 5.5.11 for failure to comply with the TS Bases Control Program. Specifically, the licensee made a change to the TS Bases, which affected TS 3.8.1, without receiving prior approval from the NRC. The licensee immediately declared equipment affected by TS 3.8.1 inoperable, namely one source of offsite power, and restored it in an expeditious manner. The licensee entered the issue into their corrective action program as CR 2011-02474.

  The inspectors determined that the violation was more than minor because in order to perform its regulatory function, the NRC relies on licensees to comply with their licensing basis documents and request prior approval for changes that may affect these documents. Because this issue affected the NRC's ability to perform its regulatory function, it was evaluated using the traditional enforcement process. The inspectors determined that the underlying technical issue could be evaluated using the SDP. Specifically, the Unit 1 transformer, a source of offsite power, was unavailable for longer than allowed by TS 3.8.1. The finding was more than minor because it impacted the Human 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. Based on the Phase 3 analysis using IMC 0609, Appendix A, for At-Power situations, the inspectors, in conjunction with a regional senior reactor analyst (SRA), determined that the finding was of very low safety significance (Green). This finding has no cross-cutting aspect as it was not representative of current performance. (Section 1R15.1)

Cornerstone: Mitigating Systems

- Green. The inspectors identified a finding of very low safety significance and associated NCV of TS 5.4.1.a for failure to implement a maintenance procedure for safety-related equipment required by Regulatory Guide 1.33, "Quality Assurance Program

Requirements (Operation)." Specifically, the licensee performed an internal inspection on the 'B' train of the annulus exhaust gas treatment system (AEGTS) rendering the train inoperable. The inspectors determined that the licensee performed an activity that affected quality without a proper procedure in place. The licensee entered the issue into their corrective action program as condition report (CR) 2011-05530.

This performance deficiency was determined to be more than minor because it impacted the Procedure Quality 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 screened as very low safety significance (Green) by answering 'no' to questions in the Mitigating Systems column of IMC 0609, Attachment 4, Table 4a, since the remaining train of AEGTS was operable and did not result in a loss of function for the impacted components, and the inoperable train was not inoperable for longer than allowed by TS. This finding was associated with a cross-cutting aspect in the Decision Making component of the Human Performance cross-cutting area because the licensee did not use conservative assumptions to ensure the proposed action was safe. Specifically, the licensee did not evaluate the impact of performing the internal inspection on the operability of the system and utilized an operator to take action if the system was called upon to perform its design function. (H.1(b)) (Section 1R15.2)

- Green. The inspectors identified a finding of very low safety significance and associated NCV of License Condition 2.C.6 for the failure to install heat detectors in the emergency diesel generator (EDG) rooms in accordance with their listed approval. Specifically, the detectors were installed at a height of 24 feet, which was in excess of approved ceiling height without appropriate reduction of spacing for ceiling height. The licensee entered the issue into their corrective action program as CR 2011-06242 and planned to evaluate modifications to address the issue.

  The finding was determined to be more than minor because the failure to install heat detectors in accordance with their listed approval was associated with the Mitigating Systems Cornerstone attribute of protection against external factors (fire) and adversely affected the cornerstone objective of ensuring the reliability and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the high installation height for the detectors without appropriate reduced detector spacing would result in requiring a larger fire and a delay in carbon dioxide system actuation. This finding was of very low safety significance using IMC 0609, Appendix F, "Fire Protection Significance Determination Process," because a fire involving an EDG would only affect the EDG involved in the fire due to the substantive fire barriers between the EDG rooms. The evaluated conditions were not significant risk contributors. The inspectors did not identify a cross-cutting aspect associated with the finding because the finding was not representative of current performance. (Section 4OA5.1)

Cornerstone: Barrier Integrity

- Green. A finding of very low safety significance and an associated NCV of Title 10 of the Code of Federal Regulations (CFR) Part 50, Appendix B, Criterion III, "Design Control," was identified by the inspectors for failure to provide adequate design control measures for crane support structure elements which included bridge crane rail, bridge crane rail clips, bridge crane rail clip studs, leveling plate and leveling plate anchors. Specifically, for evaluation of these structural elements, the licensee failed to demonstrate Seismic

Category I compliance in accordance with their design and licensing basis and failed to evaluate the structural elements for resulting reaction forces from the Fuel Handling Building crane. The licensee documented these issues in CRs 11-88791; 11-90252; 10-86582; and 11-04124.

The performance deficiency was determined to be more than minor because if left uncorrected the performance deficiency could lead to a more significant safety concern if independent spent fuel storage installation (ISFSI) loading was conducted. The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Phase 1 - Initial Screening and Characterization of Findings," Table 4a for the Barrier Integrity cornerstone. Based on answering "No" to all the questions in the Barrier Integrity Cornerstone column of Table 4a, the finding was determined to be of very low safety significance (Green).

The inspectors identified a Human Performance, Work Practices (H.4.c) cross-cutting aspect associated with this finding, in that the licensee did not ensure effective supervisory and management oversight of work activities, including contractors, such that nuclear safety was supported. Specifically, the licensee failed to have adequate oversight of design calculations and documentation for establishing structural adequacy of the rail, rail clips, rail clip bolts, leveling plate and leveling plate anchors. (H.4(c)) (Section 4OA5.2)

Cornerstone: Public Radiation Safety

- Green. The inspectors identified a finding of very low safety significance (Green) and associated NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for the licensee's failure to maintain the plant underdrain system as described in the Updated Safety Analysis Report (USAR) using adequate design control measures. Specifically, the inspectors determined that the plant underdrain system's condition was unable to support maintaining a design underground water table level of less than 568 feet with the automatic level detection and pumping system as described the USAR. As a result of this inability to maintain the system, a postulated Chapter 15 accident associated with a possible radiation waste tank failure required recalculation to demonstrate radiation safety for the public. The issue was placed in the licensee's corrective action program as CR 2011-07169, Plant Underdrain Groundwater Level Readings Non-Conservative Acceptance Criteria. The site took immediate actions to upgrade the installed system and is utilizing temporary manually operated pumps to assist the normally installed systems.

  The performance deficiency was screened in accordance with IMC 0612, Appendix B, "Issue Screening" and determined to be more than minor. None of the IMC 0612, Appendix E examples described this scenario but the inspectors determined that if left uncorrected the performance deficiency had the potential to lead to a more significant radiological safety concern by creating a liquid effluent release path that was not evaluated for radiological dose impact to the public prior to discharge and thus was more than minor. The finding was reviewed for significance in accordance with IMC 0609, Attachment 0609.04, "Phase 1 – Initial Screening and Characterization of Findings," and determined that the finding affected the Public Radiation Safety cornerstone, Effluent Release Program. The finding was then reviewed for significance by the inspectors in accordance with IMC 0609, Appendix D, "Public Radiation Safety Significance

Determination Process," and determined to be of very low safety significance. Specifically, the finding did not involve radioactive material control or the radiological environmental monitoring program. The finding was not a failure to implement the radiological effluent release program and public doses values were not greater than 10 CFR Part 50, Appendix I, criteria or 10 CFR 20.1301(e) criteria. The finding was associated with a cross-cutting aspect in the Corrective Action Program component of the Problem Identification and Resolution cross-cutting area because the licensee did not thoroughly evaluate problems such that the resolutions addressed causes and extent of conditions. Specifically, numerous deficiencies previously identified with the plant underdrain system were not addressed in enough detail to thoroughly evaluate the problem and extent of condition to allow the system to maintain the plant underground water table at USAR described levels. (P.1(c)) (Section 1R22)

B. Licensee-Identified Violations

One violation of very low safety significance that was identified by the licensee has been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. This violation and corrective action tracking number are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

The plant began the inspection period at 100 percent power. On October 2, 2011, at 1437 hours the plant was shut down due to the failure of the Unit 1 startup transformer. On October 18, 2011, at 0351 hours the plant was placed in startup mode and achieved criticality at 0938 hours on the same day. On October 19, 2011, at 1317 hours the plant generator was synchronized to the grid. With the exception of minor reductions in power to support routine surveillances and rod pattern adjustments, the plant remained at full power for the remainder of the quarter.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Winter Seasonal Readiness Preparation

a. Inspection Scope

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

- auxiliary boiler systems, and
- building heating systems.

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

b. Findings

No findings were identified.

.2 Readiness for Impending Adverse Weather Condition – Significant Snow Fall

a. Inspection Scope

Significant snow fall was predicted for December 27, 2011, and was the first winter weather of the season. The inspectors reviewed the licensee's overall preparations for the expected weather conditions. On December 27, 2011, the inspectors walked down the plant site to verify that cold weather precautions were in place and that equipment had been stored properly to be available throughout the winter weather period. The inspectors evaluated the licensee staff's preparations against the site's procedures and determined that the staff's actions were adequate. During the inspection, the inspectors focused on plant-specific design features and the licensee's procedures used to respond to specified adverse weather conditions. The inspectors evaluated operator staffing and accessibility of controls and indications for those systems required to control the plant. Additionally, the inspectors reviewed the USAR and performance requirements for systems selected for inspection, and verified that operator actions were appropriate as specified by plant-specific procedures. The inspectors also reviewed a sample of CAP items to verify that the licensee identified adverse weather issues at an appropriate threshold and dispositioned them through the CAP in accordance with station corrective action procedures. Specific documents reviewed during this inspection are listed in the Attachment.

This inspection constituted one sample for readiness for impending adverse weather conditions as defined in IP 71111.01-05.

b. Findings

No findings were identified.

1R04 Equipment Alignment (71111.04)

.1 Partial System Walkdowns

a. Inspection Scope

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

- 'A' emergency service water system;
- 'B' AEGTS;
- 'A' emergency closed cooling train; and
- Division 1 EDG.

The inspectors selected these systems based on their risk-significance relative to the Reactor Safety Cornerstone 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, 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 CAP with the appropriate significance characterization. Documents reviewed are listed in the Attachment.

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

b. Findings

No findings were identified.

.2 Complete System Walkdown

a. Inspection Scope

On November 29, 2011, the inspectors performed a complete system alignment inspection of the reactor core isolation cooling system to verify the functional capability of the system. This system was selected because it was considered both safety significant and risk significant in the licensee's probabilistic risk assessment. The inspectors walked down the system to review mechanical and electrical equipment line ups, electrical power availability, system pressure and temperature indications, as appropriate, component labeling, component lubrication, component and equipment cooling, hangers and supports, operability of support systems, and to ensure that ancillary equipment or debris did not interfere with equipment operation. A review of a sample of past and outstanding work orders was performed to determine whether any deficiencies significantly affected the system function. In addition, the inspectors reviewed the CAP database to ensure that system equipment alignment problems were being identified and appropriately resolved. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one complete system walkdown sample as defined in IP 71111.04-05.

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05AQ)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

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

- Fire Zone 1DG-1d (Diesel Generator Building Hallway 620’ Elevation);
- Fire Zone 0IB-1 (Intermediate Building 574’ Elevation);
- Fire Zones 0IB-4, 5 (Intermediate Building 654’-6”, 665’, and 682’ Elevations);
- Fire Zones 0FH-1, 2 (Fuel Handling Building 574’-10” and 599’ Elevations); and
- Fire Zone 0CC-2 (Control Complex 599’ Elevation).

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, 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.

.2 <u>Annual Fire Protection Drill Observation</u> (71111.05A)

a. <u>Inspection Scope</u>

On December 1, 2011, the inspectors observed the fire brigade activation in response to a simulated electrical fire in the 'C' control complex chilled water area of the control complex 574’ elevation. Based on their observations, the inspectors evaluated the readiness of the plant fire brigade to fight fires. The inspectors verified that the licensee staff identified deficiencies; openly discussed them in a self-critical manner at the drill debrief, and took appropriate corrective actions. Specific attributes evaluated were:

- proper wearing of turnout gear and self-contained breathing apparatus;
- proper use and layout of fire hoses;
- employment of appropriate fire fighting techniques;
- sufficient firefighting equipment brought to the scene;
- effectiveness of fire brigade leader communications, command, and control;
- search for victims and propagation of the fire into other plant areas;
- smoke removal operations;
- utilization of pre-planned strategies;
- adherence to the pre-planned drill scenario; and
- drill objectives.

Documents reviewed are listed in the Attachment to this report.

These activities constituted one annual fire protection inspection sample as defined in IP 71111.05-05.

b. Findings

No findings were identified.

1R06 Flood Protection Measures (71111.06)

Internal Flooding

a. Inspection Scope

The inspectors reviewed selected risk-important plant design features and licensee procedures intended to protect the plant and its safety-related equipment from internal flooding events. The inspectors reviewed flood analyses and design documents, including the USAR, engineering calculations, and abnormal operating procedures to identify licensee commitments. The specific documents reviewed are listed in the Attachment to this report. In addition, the inspectors reviewed licensee drawings to identify areas and equipment that may be affected by internal flooding caused by the failure or misalignment of nearby sources of water, such as the fire suppression or the circulating water systems. The inspectors also reviewed the licensee's corrective action documents with respect to past flood-related items identified in the CAP to verify the adequacy of the corrective actions. The inspectors performed a walkdown of the residual heat removal train B room during high sump level conditions to assess the adequacy of watertight doors and verify drains and sumps were clear of debris and were operable, and that the licensee complied with its commitments.

This inspection constituted one internal flooding sample as defined in IP 71111.06-05.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11Q)

a. Inspection Scope

On November 30, 2011, the inspectors observed a crew of licensed operators in the plant's simulator during licensed operator just-in-time training to support startup from Refueling Outage 13. The inspectors verified that operator performance was adequate, evaluators were identifying and documenting crew performance problems, and training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

- licensed operator performance;
- crew's clarity and formality of communications;
- ability to take timely actions in the conservative direction;
- prioritization, interpretation, and verification of annunciator alarms;
- correct use and implementation of abnormal and emergency procedures;
- control board manipulations;
- oversight and direction from supervisors; and
- the 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 sample for the quarterly licensed operator requalification program as defined in IP 71111.11.

b. Findings

No findings were identified.

.2 Biennial Written and Annual Operating Test Results (71111.11A)

a. Inspection Scope

The inspectors reviewed the overall pass/fail results of the Annual Operating Test, administered by the licensee from October 31 through December 14, 2011, required by 10 CFR 55.59(a). The results were compared to the thresholds established in IMC 0609, Appendix I, "Licensed Operator Requalification Significance Determination Process (SDP)," to assess the overall adequacy of the licensee's Licensed Operation Requalification Training Program to meet the requirements of 10 CFR 55.59.

This inspection constitutes one annual licensed operator requalification inspection sample as defined in IP 71111.11A.

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:

- steam bypass and pressure regulator system;
- Unit 1 startup transformer; and
- 10 CFR 50.65(a)(3) report.

The inspectors 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 three samples for quarterly maintenance effectiveness 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:

- reactor protection system supply bus switching;
- removal and repair of the '1A' moisture separator reheater second stage drain tank; and
- Division 1 EDG extended maintenance outage.

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

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

b. Findings

No findings were identified.

1R15 Operability Determinations and Functional Assessments (71111.15)

a. Inspection Scope

The inspectors reviewed the following issues:

- Unit 1 auxiliary transformer credited as an offsite source for TS 3.8.1;
- motor-operated main generator disconnect switch not operable in electric mode;
- residual heat removal train 'A' status during valve line-up and venting while in service for shutdown cooling;
- impact on reactor vessel systems and instrumentation while utilizing condenser vacuum to support startup; and
- Annulus Exhaust Gas Treatment System (AEGTS) operability with side panels removed.

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.

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

b. Findings

.1 Failure to Comply with Technical Specification 5.5.11, Technical Specification Bases Control Program

Introduction: The inspectors identified a Severity Level IV NCV of TS 5.5.11 for failure to comply with the TS Bases Control Program. Specifically, the licensee changed the TS Bases, which altered the application of TS 3.8.1, without receiving prior approval from the NRC.

Description: On September 26, 2011, during a review of plant status, the inspectors noted the Unit 1 startup transformer was removed from service and declared inoperable early in the morning to support planned maintenance. However, the licensee did not enter TS 3.8.1 Condition A and did not perform the Required Actions for having one offsite circuit inoperable. Discussions with the licensee identified the TS Bases included a backfeed lineup through the auxiliary transformer as a qualified circuit.

The backfeed circuit is an offsite power lineup that powers the auxiliary transformer from the grid by supplying power backwards through the main transformer. To utilize this method, the main turbine generator must be offline and disconnected from the main transformer. This lineup has no automatic features and must be manually aligned. The inspectors questioned the operability of the backfeed circuit and what documentation supported the licensee's position. Additionally, the inspectors questioned the licensee regarding any operator actions and how those were credited to support operability.

The licensee supplied documentation that stated on May 24, 1996, the TS 3.8.1 Bases was changed after the licensee had a failure of the Unit 1 startup transformer. The licensee performed an internal review of their licensing documents and then processed a change to the TS Bases for TS 3.8.1 to include the backfeed capability as an additional qualified offsite circuit. The licensee processed this change as an administrative change and did not consider it as affecting TS 3.8.1.

After several discussions between the NRC and the licensee, the NRC determined that the licensee was not licensed to include the backfeed capability as a qualified offsite circuit. It was identified in the licensee's Safety Evaluation Report and the USAR as an alternate method of offsite power that was included in the design of the plant. However, it was not identified as a qualified offsite circuit to satisfy TS. Only the two startup transformers were credited as providing qualified offsite circuits. Upon notification that the backfeed circuit was not considered a qualified circuit; the licensee immediately entered the associated Condition and Required Actions of TS 3.8.1.

On September 28, 2011, the licensee restored the Unit 1 startup transformer and declared it operable within the allowed TS Required Action time. Subsequently, on September 29, 2011, the unit startup transformer catastrophically failed. The licensee declared the transformer inoperable and entered the Conditions and Required Actions of TS 3.8.1. Knowing the transformer would not be returned to service within the allowed TS action time, the licensee shut down the plant. The licensee obtained a one-time TS Amendment from the NRC to operate with Unit 1 startup transformer out of service for a limited amount of time while a temporary modification utilizing a non-like-for-like transformer was installed as a replacement. This event is discussed in Section 1R20.

Analysis: The inspectors determined that the licensee's failure to follow TS 5.5.11 constituted a performance deficiency. Specifically, the licensee made a change to the TS Bases that altered the application of TS 3.8.1 without prior NRC approval. This change affected the licensee's determination of the number of offsite circuits available to satisfy TS 3.8.1 and resulted in the licensee failing to enter the Conditions and associated Required Actions when not meeting the TS 3.8.1 requirements. The inspectors reviewed this issue in accordance with IMC 0612, Appendix B, and the discussion for Block 7, Figure 2, Paragraph 2.a.ii., and determined that a failure to receive prior NRC approval for changes in licensed activities was an example of a violation that impacted the regulatory process and was subject to traditional enforcement. Consistent with the guidance in Section 6.1, Paragraph d., of the NRC Enforcement Policy, this performance deficiency was determined to be a Severity Level IV NCV. This performance deficiency has no cross-cutting aspect as it was strictly associated with a traditional enforcement violation. In accordance with NRC policy, the underlying technical issue was required to be evaluated using the SDP. The NRC used the SDP results to validate the severity of the traditional enforcement violation.

The inspectors determined that the underlying technical issue could be evaluated using the SDP. Specifically, the Unit 1 transformer, a source of offsite power, was unavailable for longer than allowed by TS 3.8.1. The inspectors evaluated the performance deficiency in accordance with IMC 0612, Appendix B, "Issue Screening." This performance deficiency was not similar to any of the examples in IMC 0612, Appendix E, "Examples of Minor Issues," but was characterized as more than minor because it impacted the Human 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 inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Phase 1 - Initial Screening and Characterization of Findings," Table 4a for the Initiating Events Cornerstone. The inspectors determined the finding could contribute to the likelihood that mitigation equipment or functions would not be available. A Phase 2 SDP evaluation was performed using IMC 0609, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations."

As stated in Licensee Event Report (LER) 2011-002-00 for Perry Nuclear Power Plant, there were eight instances that were found in the past 3 years, which involved approximately 438 hours, where either the Unit 1 startup transformer (SUT) or the Unit 2 SUT was declared inoperable and the backfeed lineup was designated as a source of offsite power.

Using the Risk-Informed Inspection Notebook for Perry Nuclear Power Plant (Revision 2.1a), as a bounding assumption, the performance deficiency for either the Unit 1 or Unit 2 SUT being unavailable for 438 hours (i.e., 3-30 days) was evaluated considering recovery of AC (alternating current) sources with a result of one "8" (from Table 3.7, Loss of Offsite Power Worksheet), or a finding of very low risk significance (Green). In addition, to corroborate the Phase 2 result, a Phase 3 SDP evaluation was performed.

The Senior Reactor Analysts (SRAs) performed a Phase 3 internal events SDP evaluation of the finding using SAPHIRE Version 8.0.7.17 and the Perry Standardized

Plant Analysis Risk (SPAR) model (Version 8.15). Using the SPAR model, the risk significance of the Unit 2 SUT being unavailable was determined to be insignificant in relation to the Unit 1 SUT for the same time period of unavailability, and thus the unavailability of the Unit 2 SUT did not need to be evaluated. After reviewing the time periods when the Unit 1 SUT was unavailable over the last 3 years, it was determined that the exposure time for the finding was 240 hours or 10 days. This time was based on the most limiting time in any 1-year period in which the Unit 1 SUT was unavailable.

Using the SPAR model, a bounding assessment was obtained for the change in core damage frequency (CDF) for the maximum of 10 days that the Unit 1 SUT was unavailable during a given 1-year period over the last 3 years. The bounding assessment assumed that all of the safety buses were initially powered from the Unit 1 SUT, the Unit 1 SUT subsequently failed, and that a transfer of site loads from the Unit 1 SUT to the Unit 2 SUT was then required. If the Unit 1 SUT did not fail, but instead was being taken out of service for maintenance work, the change in CDF would be less, since the Unit 1 SUT would not have been made unavailable until the transfer of site loads to the Unit 2 SUT was completed.

The result of the bounding assessment was a change in CDF of 2.4E-7/yr. The two dominant core damage sequences involved (1) a grid-related loss of offsite power (LOOP) initiating event with a failure of emergency power, suppression pool cooling, containment venting, and late injection, and (2) a grid-related LOOP initiating event with a failure of the emergency power system, high-pressure core spray, suppression pool cooling, low-pressure injection, containment venting, and late injection

Since the total estimated change in CDF was greater than 1.0E-7/yr, Inspection Manual Chapter (IMC) 0609, Appendix A, Attachment 3, “User Guidance for Screening of External Events Risk Contribution,” was used to screen external event contributions.

The seismic risk contribution was screened, since during a representative seismic event, a LOOP is normally expected to occur, and as such, there would no delta risk by having the Unit 1 SUT initially unavailable. Therefore, per IMC 0609, Appendix A, Attachment 3, the seismic risk should be considered insignificant to the finding.

Flooding scenarios were screened using IMC 0609, Appendix A, Table 3.1, “Plant Specific Flood Scenarios.” The guidance lists structures, systems, and components important to internal flooding (e.g., high-pressure core spray and the safety relief valves) and a LOOP would not significantly affect the flooding scenarios identified for Perry.

An evaluation of the risk from plant fires was estimated using the information provided in the licensee’s Individual Plant Examination for External Events (IPEEE) dated June 1996 and the Perry SPAR model. The contribution to the risk of the finding is limited to fires that cause a loss of EDGs for Division 1 and Division 2. From the Perry IPEEE, one main control board cabinet (cabinet P877) was evaluated that had the potential to cause a loss of the Division 1 and Division 2 EDGs. Fires that cause a loss of Division 1 and Division 2 EDGs were evaluated for the case where main control room evacuation was not required and for the case where main control room evacuation was required. The total change in CDF from fires due to the performance deficiency was evaluated to be insignificant (1.2E-10/yr).

The potential risk contribution for this finding from large early release frequency (LERF) was screened using the guidance of IMC 0609 Appendix H, “Containment Integrity

Significance Determination Process." Perry is a boiling water reactor with a Mark III containment. Sequences important to LERF for a Mark III containment include inter-system loss-of-coolant accidents (ISLOCAs), transients and small break LOCAs (i.e., high reactor coolant system (RCS) pressure sequences), and station blackout (SBO) sequences. For the Phase 3 analysis, SBO and high RCS pressure sequences were the dominant core damage sequences for this finding. Per Table 5.2, "Phase 2 Assessment Factors – Type A Findings at Full Power," of IMC 0609, Appendix H, sequences involving SBO and high RCS pressure have a LERF factor of 0.2. Using this LERF factor, the risk significance due to LERF was estimated to be 4.8E-8/yr (Green).

Based on the Phase 3 analysis, the inspectors confirmed that the ROP finding was of very low safety significance (Green). This finding does not have a cross-cutting aspect because the performance deficiency is not representative of current performance.

Enforcement: Technical Specification 5.5.11 requires, in part, that if the licensee makes a change to the Bases which requires a change to the TS incorporated in the license, it shall be reviewed and approved by the NRC prior to implementation. Contrary to the above, on May 24, 1996, the licensee made a change to the TS 3.8.1 Bases that altered the application of TS 3.8.1 and required a change to the TS. Specifically, the licensee added a delayed backfeed circuit (which was not qualified) into the Bases as a qualified offsite source changing the number of available offsite circuits from two to three. TS 3.8.1 Required Action A, allows a 72 hour completion time with only one offsite power source available; Required Action F requires you to be in Mode 3 in 12 hours if the required action and completion time are not met.

In accordance with the Enforcement Policy, this violation was classified as a Severity Level IV violation because the underlying technical issue was of very low risk significance. Immediate actions for this issue included entering TS 3.8.1 Condition A, Required Actions and commencing restoration activities on the Unit 1 SUT. Because this issue was of very low safety significance, was not repetitive or willful, and was entered into the licensee's CAP as CR 2011-02474, this violation is being treated as an NCV, consistent with Section 2.3.2 and Section 6.1 of the NRC Enforcement Policy **(NCV 05000440/2011005-01; Failure to Comply with TS 5.5.11, TS Bases Control Program**).

Also contrary to the above, during various times between 1996 and September 2011 (based on the record of uses of backfeed incorrectly as a qualified source), the licensee failed to comply with TS 3.8.1 Required Action F and be in mode 3 within 12 hours when the completion time was not met. Because the finding discussed above was evaluated separately using the SDP, it is required to be tracked separately and will be given a separate tracking number **(NCV 05000440/2011005-02; Failure to Comply with TS 5.5.11, TS Bases Control Program)**.

.2 Failure to Establish a Procedure to Perform Maintenance on Safety-Related Equipment

Introduction: The inspectors identified a finding of very low safety significance (Green) with an associated NCV of TS 5.4.1.a for the failure to implement a maintenance procedure, as required by Regulatory Guide 1.33, on the 'B' train of the AEGTS, a safety related piece of equipment. The maintenance which was conducted rendered the train inoperable but because of the failure to utilize written procedures no associated TS action statements were entered as required.

Description: On November 9, 2011, while performing a review of recently performed routine maintenance and testing on the 'B' train of AEGTS, it was identified that one of the upstream high-efficiency particulate filter tension bars was loose. Investigation identified that while performing the testing on the 'B' AEGTS train, the tension bar was restored to its required position, but was reported as not functioning properly (placing tension on filter). Condition Report 2011-05158 was initiated. A past operability review was completed on November 18, 2011, and determined there was no past adverse affect to the system.

On November 11, 2011, because of the question regarding the functionality of the tension bars, the licensee inspected all the tension bars in the 'B' AEGTS train. This inspection was an internal inspection and required removal of panels on the side of the filter plenum. These panels are hinged and dogged in place. The inspection verified all filter tension bars were secure and functioning properly. Additionally, on November 16, 2011, the licensee again inspected the tension bars which required opening of the panels on the side of the filter plenum. Both of these inspections were performed without utilizing maintenance work documents.

The inspectors questioned the licensee regarding operability of the system with the side panels open and the documentation of the inspection. The licensee entered this concern in their CAP as CR 2011-05530, performed an evaluation, and determined the system was not operable with the side panels open. Consequently this resulted in two instances where the licensee failed to declare the 'B' AEGTS train inoperable and enter the Conditions and Required Actions of TS 3.6.4.3. The time the system was inoperable was less than the Required Action A completion time of 7 days.

Analysis: The inspectors determined that the failure to properly pre-plan and perform maintenance on safety-related equipment in accordance with written procedures, as required by TS 5.4.1.a and Regulatory Guide 1.33, was a performance deficiency. Specifically, the licensee conducted inspection activities on the ‘B’ AEGTS train without work documents or plant procedures. The inspectors evaluated the performance deficiency in accordance with IMC 0612, Appendix B, “Issue Screening.” This performance deficiency was not similar to any of the examples in IMC 0612, Appendix E, “Examples of Minor Issues," but was characterized as more than minor because it impacted the Procedure Quality 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 inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, “Significance Determination Process,” Attachment 0609.04, “Phase 1 - Initial Screening and Characterization of findings,” Table 3b for the Mitigating Systems Cornerstone. The inspectors determined the finding was of very low safety significance (Green) because it was not a design/qualification deficiency, did not represent a loss of system safety function, did not result in a loss of function of a single train for greater than its TS allowable outage time, did not result in a loss of function of nonsafety-related risk-significant equipment and was not risk significant due to external events.

This finding has a cross-cutting aspect in the Decision Making component of the Human Performance cross-cutting area per IMC 0310 (H.1(b)) because the licensee did not use conservative assumptions to ensure the proposed action was safe. Specifically, the licensee failed to evaluate the consequences of opening the side panels on the 'B' AEGTS train prior to performing maintenance. Additionally, the licensee posted an operator to take manual action and close the door if the system was called upon to perform its design function as a contingency.

Enforcement: Technical Specification 5.4.1.a requires that written procedures be established, implemented, and maintained for the activities specified in Regulatory Guide 1.33, Revision 2, Appendix A. Regulatory Guide 1.33, states, in part, that "maintenance that can affect the performance of safety-related equipment should be properly pre-planned and performed in accordance with written procedures." Contrary to the above, on November 11, 2011, and November 16, 2011, the licensee performed maintenance activities on a safety-related system without a procedure or work document. Specifically, the licensee performed internal inspections on the 'B' AEGTS train which required removal of filter plenum side panels. This action rendered the 'B' AEGTS train inoperable and should have caused the licensee to enter the applicable TS action. Because this violation was of very low safety significance and it was entered into the licensee's CAP as CR 2011-05530, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy.
(NCV 05000440/2011003-03, Failure to Establish a Procedure to Perform Maintenance on Safety-Related Equipment)

1R18 Plant Modifications (71111.18)

a. Inspection Scope

The inspectors reviewed the modification 11-0626; "Temporary Installation of Davis-Besse Transformer for Perry Unit 1 Startup Transformer."

The inspectors reviewed the configuration changes and associated 10 CFR 50.59 safety evaluation screening against the design basis, the USAR, and the TS, as applicable, to verify that the modification did not affect the operability or availability of the affected system(s). 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 the operation 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 plant modification sample 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:

- scram discharge volume vent and drain valve solenoid replacement during the week of November 14, 2011;
- heater bay ventilation fan 'B' repair testing during the week of November 14, 2011;
- Unit 1 SUT replacement testing during the weeks of November 14, and 21, 2011;
- drywell equipment drain sump recorder card replacement and retest; and
- Division 1 emergency diesel generator (EDG) testing during the week of December 19, 2011.

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 TS, 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 five post-maintenance testing samples as defined in IP 71111.19-05.

b. Findings

No findings were identified.

1R20 Other Outage Activities (71111.20)

a. Inspection Scope

The inspectors evaluated outage activities for a forced outage that began on October 2, 2011, and continued through the October 19, 2011. 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 was caused by a failure of the Unit 1 SUT which placed the unit in TS 3.8.1 which requires a shutdown when repairs cannot be completed within the allotted time. The failure of the transformer was a rupture of the oil containment system and was not repairable in the allowed time so the unit was shut down to conduct the repairs. A one-time TS Amendment was eventually approved to allow the plant to start up with backfeed through the auxiliary transformer as the second means of offsite power supply using risk-informed analysis until the transformer could be replaced with a temporary modification. The inspectors actively participated in the development of a one-time TS amendment and inspected the licensee's implementation of the requirements in the license amendment. A failure to ensure the offsite lineup was identified by the licensee and an NCV of very low safety significance is documented in Section 4OA7.

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:

- containment/drywell integrity verification;
- standby liquid control system boron sampling;
- high-pressure core spray pump and valve operability inservice testing;
- use of alternate drain calculation procedures for equipment drain sump readings (RCS leakage);
- under-drain sump testing procedures; and
- Division 1 diesel generator monthly surveillance for operability.

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

- did preconditioning occur;
- were the effects of the testing adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- were acceptance criteria clearly stated, demonstrated operational readiness, and consistent with the system design basis;
- plant equipment calibration was correct, accurate, and properly documented;
- as-left setpoints were within required ranges, and the calibration frequency were in accordance with TS, 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 Engineer's 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;
- 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 four samples for routine surveillance testing, one sample for inservice testing, and one sample for RCS leak detection as defined in IP 71111.22, Sections -02 and -05.

b. Findings

Introduction: The inspectors identified a finding of very low safety significance (Green) with an associated NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for the licensee's failure to assure that applicable regulatory requirements and the design basis for structures, systems, and components are correctly translated into specifications, drawings, procedures, and instructions. Specifically the plant underdrain system as described in the USAR, was not maintained in a condition which would allow the system to automatically keep the underground water table level below 568 feet at the Perry site as assumed in a postulated Chapter 15 accident scenario associated with a possible radiation waste tank failure. The scenario subsequently required recalculation to demonstrate radiation exposure safety for the public.

Description: On November 27, 2011, the inspectors noted that the licensee evaluated leakage into the residual heat removal 'B' pump room of the auxiliary building as being caused by the high water level in the plant underdrain system causing groundwater in-leakage. An inspection of the residual heat removal 'B' pump room by the inspectors did not reveal a source of in-leakage to the room. Subsequently, while reviewing CR-2011-06461, the inspectors noted that the licensee was unable to meet the requirements to conduct a USAR, Section 2.4.13.5.4.b, required semi-annual groundwater inflow test. The inspectors conducted a post-test evaluation of the Plant Underdrain Groundwater

Inflow Test, Periodic Test Instruction (PTI)-P72-P0002, and the write-ups in several CRs to determine the underdrain system status. Questions were asked of the licensee and the inspectors observed the actions to attempt restoration of the underdrain system level to less than the 568 foot level required in the USAR.

The licensee analyzed previous inflow tests and based on current pumping capacity from installed and temporary pumps installed in the system, evaluated the inflow rate to the underdrain system to be less than 80 gallons per minute. This is the limiting inflow rate to the underdrain system and would challenge the calculation assumptions of the plant's ability to maintain accidental discharges within the requirements of 10 CFR Part 20 in the event that radioisotopes were to leak into the underdrain system. The previous 12 months were extremely wet with record precipitation in the Cleveland metropolitan area and without actually completing the PTI, the licensee could not definitively state that the system would support the accident analysis delay times in the Chapter 15 calculations for a radiation waste tank rupture. The accident calculations assume that level is maintained at less than 568 feet and the inflow is less than 80 gallons per minute. On November 27, 2011, the underdrain levels reached 574 feet 5 inches, with only two pumps operating, one the normally installed pump and one temporary pump. The pumps were struggling to keep up with the inflow of water. The licensee upgraded several work orders, one of which was originally planned to be worked in July 2010 but which had been repeatedly deferred and is now scheduled for late February 2012.

A prompt functionality assessment was completed on December 30, 2011, and determined that the system was functional but "full qualification is not achieved" and recommended compensatory measures to use temporary pumps to lower the plant underdrain level and taking of level readings on a daily basis. The licensee reported this issue as an 8 hour, non emergency report, under 10CFR 50.72 as Event Notification EN 47545, "Groundwater Level May Exceed Design Assumptions." Compensatory measures have been taken by the licensee and repairs were in progress at the time the inspection period ended. With compensatory actions in place, there is no current safety concern. Final review of the revised calculations are not complete but the initial review of the radiation waste tank rupture calculation, Calculation 3.1.3.1, showed that a level of 575 feet in the plant underdrain system provided adequate volume to support the delay time required in the postulated radioactive waste tank rupture scenario.

<u>Analysis</u>: The inspectors determined that failing to maintain the plant underdrain system with a USAR described capability to automatically maintain the underground water table level below 568 feet was a performance deficiency. Specifically the licensee failed to conduct maintenance on the pumps and control elements so that the automatic capability of the underdrain system was functional, directly leading to the systems inability to support a Chapter 15, USAR, postulated radiation waste tank rupture calculation and a potential subsequent public radiation exposure event in the case of such an accident. Therefore, while the system is a mitigating system for plant impact of local high water table issues, this issue was also a performance deficiency which impacted the Public Radiation Safety Cornerstone. The performance deficiency was screened in accordance with IMC 0612, Appendix B, "Issue Screening" and determined to be more than minor. None of the IMC 0612, Appendix E, examples described this specific scenario but the inspectors determined that if left uncorrected, the performance deficiency had the potential to lead to a more significant radiological safety concern by

creating a liquid effluent release path that was not evaluated for radiological dose impact to the public prior to discharge.

The finding was reviewed for significance by the inspectors in accordance with IMC 0609, “Significance Determination Process,” Attachment 0609.04, “Phase 1 – Initial Screening and Characterization of Findings,” and determined that the finding affected the Public Radiation Safety cornerstone, Effluent Release Program. Screening under IMC 0609, Appendix D, “Public Radiation Safety Significance Determination Process” determined the finding to be of very low safety significance (Green). Specifically, the finding did not involve radioactive material control or the radiological environmental monitoring program. The finding was not a failure to implement the radiological effluent release program and public doses values were not greater than 10 CFR Part 50, Appendix I criteria or 10 CFR 20.1301(e) criteria.

The finding has a cross-cutting aspect in the CAP component of the Problem Identification and Resolution cross-cutting area per IMC 0310 (P.1(c)) because the licensee did not thoroughly evaluate problems such that the resolutions addressed causes and extent of conditions. Specifically, numerous deficiencies previously identified with the plant underdrain system were not addressed in enough detail to thoroughly evaluate the problem and allow the system to maintain the plant underground water table at USAR described levels in December of 2011.

<u>Enforcement</u>: Title 10 of CFR, Part 50, Appendix B, Criterion III, “Design Control” states in part that “Measures shall be established to assure that applicable regulatory requirements and the design basis are correctly translated into specification, drawings, procedures and instructions.” Title 10 CFR 50.2, defines “*Design bases* means that information which identifies the specific functions to be performed by a structure, system or component of a facility, and the specific values or ranges of values chosen for controlling parameters as reference bounds for design” and “These values may be requirements derived from analysis of the effects of a postulated accident for which a structure, system or component must meet its functional goals.” Additionally, 10 CFR 20.1302, “Compliance with Dose Limits for Individual Members of the Public” states, in part, that “the licensee shall make or cause to be made, as appropriate, surveys of radiation levels in unrestricted and controlled areas and radioactive materials in effluents to be released to unrestricted and controlled areas to demonstrate compliance with the dose limits for individual members of the public in §20.1301."
As gdefined in 10 CFR 20.1003, “survey” means an evaluation of the radiological conditions and potential hazards incident to the production, use, transfer, release, disposal, or presence of radioactive material or other sources of radiation.

Contrary to the above, on December 30, 2011, it was identified that the plant underdrain system as defined in the USAR was not fully qualified to meet the capability required to support a Chapter 15, USAR, postulated radiation waste tank rupture calculation and the potential subsequent public radiation event. Therefore, adequate measures were not established to ensure the design basis was translated into the plant specifications. Because this violation was of very low safety significance and was entered into the licensee’s CAP as CR-2011-07169, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. **(NCV 05000440/2011005-04, Failure to Maintain the Plant Underdrain System Within USAR Described Capabilities)**

Cornerstone: Emergency Preparedness

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

a. Inspection Scope

Since the last NRC inspection of this program area, Emergency Plan, Revision 32, and Emergency Action Level Technical Bases, Revision 23, were implemented based on your determination, in accordance with 10 CFR 50.54(q), that the changes resulted in no decrease in effectiveness of the Plan and that the revised Plan as changed continues to meet the requirements of 10 CFR 50.47(b) and Appendix E to 10 CFR Part 50. The inspectors conducted a sampling review of the Emergency Plan changes and a review of the Emergency Action Level changes made between December 2010 and November 2011 to evaluate for potential decreases in effectiveness of the Plan. However, this review does not constitute formal NRC approval of the changes. Therefore, these changes remain subject to future NRC inspection in their entirety.

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

b. Findings

No findings were identified.

1EP6 Drill Evaluation - Training Observation (71114.06)

a. Inspection Scope

The inspectors observed a simulator training evolution for licensed operators on November 30, 2011, which required emergency plan implementation by a licensee operations crew. This evolution was planned to be evaluated and included in performance indicator (PI) data regarding drill and exercise performance. The inspectors observed event classification and notification activities performed by the crew. The inspectors also attended the post-evolution critique for the scenario. The focus of the inspectors' activities was to note any weaknesses and deficiencies in the crew's performance and ensure that the licensee evaluators noted the same issues and entered them into the CAP. As part of the inspection, the inspectors reviewed the scenario package and other documents listed in the Attachment to this report.

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

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

4OA1 Performance Indicator Verification (71151)

.1 Reactor Coolant System Leakage

a. Inspection Scope

The inspectors sampled licensee submittals for the RCS Leakage performance indicator (PI) for the period from the fourth quarter 2010 through the third quarter of 2011. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in Nuclear Energy Institute (NEI) Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, was used. The inspectors reviewed the licensee's operator logs, RCS leakage tracking data, issue reports, event reports, and NRC Integrated IRs for the period of October 2010 through September 2011 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 RCS leakage PI sample as defined in IP 71151-05.

b. Findings

No findings were identified.

.2 Mitigating Systems Performance Index - Cooling Water Systems

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index (MSPI) - Cooling Water Systems PI for the period from the third quarter 2010 through the second quarter 2011. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, was used. The inspectors reviewed the licensee's operator narrative logs, issue reports, MSPI derivation reports, event reports and NRC Integrated IRs for the period of the third quarter 2010 through the second quarter 2011 to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one MSPI cooling water system PI sample as defined in IP 71151-05.

b. Findings

No findings were identified.

4OA2 Problem Identification and Resolution (71152)

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

a. Inspection Scope

As part of the various baseline IPs discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that they were being entered into the licensee's CAP at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. Attributes reviewed included: 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 CR packages.

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

b. Findings

No findings were identified.

.3 Selected Issue Follow-Up Inspection: Mode Change with S-611 and S-610 Breaker Disconnects Open in the Main Switchyard

a. Inspection Scope

The inspectors performed an in-depth review of CR 2011-03926; "Discovered S-610 and S-611 Bounding Disconnects Danger Tagged Open by Northern Region."

The inspectors discussed the evaluation with the licensee and independently walked down the main switchyard to evaluate the issue. Assigned corrective actions were reviewed with licensee personnel and the inspectors verified the following attributes during their review of the above apparent cause evaluation:

- complete and accurate identification of the problem in a timely manner commensurate with its safety significance and ease of discovery;
- consideration of the extent-of-condition, generic implications, common cause, and previous occurrences;
- classification and prioritization of the resolution of the problem, commensurate with safety significance;
- identification of the contributing causes of the problem; and
- identification of corrective actions, which were appropriately focused to correct the problem.

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

b. Findings

A licensee-identified violation of very low safety significance is documented in Section 4OA7 of this report.

.4 Annual Sample: Review of Operator Workarounds

a. Inspection Scope

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

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

This review constituted one sample for operator workarounds 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 05000440/2011-002-00: Condition Prohibited by Technical Specifications and Plant Shutdown Due to Unit 1 Startup Transformer Issues

a. Inspection Scope

On September 26, 2011, at 0158 hours, the Unit 1 SUT was taken out of service to perform scheduled maintenance. The licensee considered that the Unit 2 SUT and a manual Unit 1 backfeed capability through the auxiliary transformer satisfied TS 3.8.1 which requires two qualified offsite circuits to be operable. Further review and consultation with the NRC determined that the backfeed lineup was not creditable as a qualified offsite circuit. The review further identified that the TS-required actions for 3.8.1 were not completed as required on September 26, 2011. The transformer was restored to service within the original time period allotted for the limiting condition for operations (LCOs) in TS 3.8.1. Subsequently on September 29, 2011, the transformer experienced an internal fault and failed at 0529 hours. Since repairs would not be completed during the LCO period the plant was shut down on October 2, 2011, at 0158 hours to support repairs to the Unit 1 startup transformer. The licensee documented the deficiency in CR 11-97305 and conducted a full apparent cause evaluation to determine the appropriate corrective actions, which included implementing two temporary modifications to remove the deficiency by lifting leads and installing jumpers. Planned corrective actions include designing and implementing a method to isolate the ammeters if a control room fire occurs and training of engineering personnel related to indication circuits and safe shutdown components. The deficiency was determined to be of low safety significance by the licensee. The Licensee Event Report (LER) and apparent cause evaluation were reviewed by the inspectors and subject of an NCV in Section 1R15.1; no additional findings or violations of NRC requirements were identified. Documents reviewed 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) Licensee Event Report 05000440/2011-003-00: Switchyard Configuration During Startup Results in Operation Prohibited from Technical Specifications

a. Inspection Scope

On October 18, 2011, at 0351 hours, the plant entered Mode 2 during plant startup. One of the two offsite power circuits required by TS 3.8.1, "AC Sources –Operating" was the delayed access circuit through the Unit 1 auxiliary transformer due the previously experienced failure of the Unit 1 SUT earlier in the month of October. At 1619 hours later the same day, the manual disconnects in the main switchyard were found to be open with danger tags installed. The failure to meet TS 3.8.1 requirements for operable equipment prior to the mode change was a performance deficiency and the licensee-identified violation is documented in Section 4OA.7. The licensee documented the deficiency in CR-2011-03926 and conducted a root cause evaluation to determine appropriate corrective actions. Immediate corrective actions were to initiate a night order which modified the tracking of switchyard configurations by control room personnel and revisions to procedures to validate switchyard configurations prior to startup, not just inside the plant equipment. The deficiency was determined to be of low safety significance by the licensee. The LER was reviewed by the inspectors and no additional findings or violations of NRC requirements were identified. Documents reviewed 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.

4OA5 Other Activities

.1 (Closed) Unresolved Item 05000440/2010006-02: Diesel Generator Rooms' Fire Protection System Concern

a. Inspection Scope

The inspectors conducted a follow-up inspection on site during the month of November 2011. Further phone conversations between the licensee, the inspectors and headquarters personnel determined that the previously unresolved item was indeed a violation of the National Fire Protection Association (NFPA) Code of Record as described in the findings section which follows.

b. Findings

Introduction: The inspectors identified a finding of very low safety significance (Green) and associated NCV of License Condition 2.C.6 for the failure to install heat detectors in the EDG rooms in accordance with their listed approval. Specifically, the detectors were installed at a height of 24 feet which was in excess of approved ceiling height without appropriate reduction of spacing for ceiling height.

Description: The detection for the Perry Nuclear Power Plant EDG rooms' carbon dioxide systems was configured such that the systems may not actuate in the event of substantial fire. The issues contributing to this condition were detector spacing which did not meet established NFPA guidelines for ceiling height considerations, cross-zoning of detectors such that a heat detector was required to activate on both sides of the rooms for the carbon dioxide systems to actuate, and, for the Division 3 EDG room, detectors which were at too high of a temperature rating when expected ceiling temperatures were considered. The detector spacing was also contrary to requirements described in the USAR.

The code of record in the USAR for detector location and spacing was standard NFPA 72E–1974, "Automatic Fire Detectors." Standard NFPA 72E–1974 did not explicitly address detector height as part of the requirements. Section B-1.2 within the NFPA 72E–1974 appendices did state that height is the most important single dimension where ceiling heights exceed 16 feet. The inspectors noted that Section 2-5.1.1 of the standard specified that all fire detection devices be approved for the purpose for which they were intended and that they be installed in conformity with the standard. The licensee was not able to obtain confirmation from the vendor that the listing for detector was valid for ceiling heights above 16 feet. The inspectors concluded that the detectors were not approved for ceiling heights above 16 feet without appropriate reduction of detector spacing for ceiling height.

The inspectors noted that more recent revisions (from at least 1984 through 2010) of the NFPA standard for detectors did provide a methodology for reduced spacing for high ceilings. The detectors had a Factory Mutual listing of 30 feet for spacing. Table 17.6.3.5.1 of NFPA 72-2010, "National Fire Alarm and Signaling Code," specified that the listed spacing be multiplied by 0.52 for heat detector spacing reduction based on ceiling height for a ceiling height of 24 feet. Based on this information, the inspectors determined that the required detector spacing was 15.6 feet (consistent with Section 17.6.3.1.1(1) of NFPA 72–2010) or a radial distance for any point on the ceiling to a detector of 10.92 feet (0.7 × 15.6 feet) (consistent with Section 17.6.3.1.1(2) of NFPA 72-2010). The installed heat detectors were laid out in a rectangular grid in each EDG room. The detectors had a 20.00 foot spacing in the east-west direction and 14.00 foot, 13.75 foot, and 15.13 foot spacings for the Divisions 1, 2, and 3 EDG rooms, respectively, in the north-south direction. The inspectors noted that the detectors did not meet the 15.6 foot spacing requirement, when ceiling height was considered, because the detectors exceeded the spacing in the east-west direction. The inspectors calculated the maximum radial distance on the ceiling from a detector as 12.21 feet, 12.14 feet, and 12.54 feet for the Divisions 1, 2, and 3 EDG rooms, respectively. As such, the detectors also exceeded the alternative radial distance requirement. The inspectors confirmed with the Office of Nuclear Reactor Regulation, the authority having jurisdiction, that the inspectors' method of calculating detector spacing was correct.

In addition to the detectors not being approved for the 24-foot ceiling height, the inspectors had identified issues with inappropriate cross-zoning of the heat detectors and, for the Division 3 EDG room, an inappropriately high temperature setpoint for the heat detectors. Independent calculations performed by the inspectors showed that the inappropriate cross-zoning resulted in the fire size necessary for activation of the suppression system being approximately double of that under the non-cross zoned arrangement associated with the original detector installation. Similarly, the inspectors' calculations showed that the inappropriately high temperature setpoint for the Division 3 EDG room heat detectors also resulted in an additional doubling of fire size needed to activate the temperature detectors over the temperature range specified by NFPA

72E - 1974 for the expected ceiling temperatures. Given the issues with inappropriate cross-zoning and, for the Division 3 EDG room, an excessively high temperature rating for the heat detectors, the inspectors determined that an engineering evaluation for justification of the inadequate detector spacing would be inappropriate.

The licensee initiated CR 2011-06242, "NRC CDBI 2011- Potential Green Non-Cited Violation (NCV)", on December 2, 2011. The licensee planned to evaluate modifying the cross-zoning arrangements such that only one heat detector, in conjunction with another type of detector (e.g., smoke detectors) would be required to actuate an EDG room suppression system. In addition, the licensee planned to modify the heat detectors in the Division 3 EDG room to actuate at a lower temperature (e.g., 225 degrees Fahrenheit (°F)) versus the existing actuation set point of 275 °F. Such modifications would allow an engineering justification of the existing detector spacing.

<u>Analysis</u>: The inspectors determined that the failure to install heat detectors in the EDG rooms in accordance with their listed approval was contrary to NFPA 72E–1974 and was a performance deficiency. Specifically, the detectors were installed at a height of 24 feet, which was in excess of approved ceiling height without appropriate reduction of spacing for ceiling height. The finding was determined to be more than minor because the failure to install heat detectors in accordance with their listed approval was associated with the Mitigating Systems Cornerstone attribute of protection against external factors (fire) and affected the cornerstone objective of ensuring the reliability and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the high installation height for the detectors without appropriate reduced detector spacing would result in requiring a larger fire and a delay in carbon dioxide system actuation.

In accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Phase I - Initial Screening and Characterization of Findings," Table 3b the inspectors determined the finding degraded the fire protection defense-in-depth strategies. Therefore, screening under IMC 0609, Appendix F, "Fire Protection Significance Determination Process," was required. The inspectors noted that a fire involving an EDG would only affect the EDG involved in the fire due to the substantive fire barriers between the EDG rooms. As such, fire scenarios involving the EDGs were equivalent to a fire damage state (FDS) of FDS0 under Step 2.2 of IMC 609, Appendix F. The inspectors determined that the finding screened to Green (i.e., very low safety significance) because FDS0 damage states are not analyzed as risk contributors in IMC 609, Appendix F.

The inspectors did not identify a cross-cutting aspect associated with this finding because the finding was not representative of current performance. Although the licensee had modified detectors as recently as 2009, the detector spacing had remained unchanged since original construction.

<u>Enforcement</u>: License Condition 2.C.6 required the licensee to implement and maintain in effect all provisions of the approved fire protection program as described in the USAR, as amended, for the Perry Nuclear Power Plant and as approved in the Safety Evaluation Report (NUREG-0887) dated May 1982 and Supplement Nos. 1 through 10 thereto. Section 9A.7 of the USAR, as amended, stated that fire detection described as provided throughout a fire area indicated that detectors are located and spaced in accordance with NFPA 72E. Sections 9A.4.5.1.1 through 9A.4.5.1.3 of the USAR, as

amended, describe fire areas 1DG-1a, 1DG-1b, and 1DG-1c for the Division 2, Division 3, and Division 1 EDG rooms, respectively. Sections 9A.4.5.1.1 through 9A.4.5.1.3 describe the areas as having fire detection throughout. Section 2-5.1.1 of NFPA 72E–1974 states all fire detection devices shall be approved for the purpose for which they are intended, and shall be installed in conformity with NFPA 72E–1974.

Contrary to the above, from June 1987 for fire areas 1DG-1a and 1DG-1c, and March 2009 for fire area 1DG-1b, through December 20, 2011, the licensee failed to implement and maintain in effect all provisions of the approved Fire Protection Program, in that the licensee failed to use fire detection devices approved for the purpose for which they were intended. Specifically, the licensee installed heat detectors at a ceiling height of 24 feet above the floor, which was above the 16 foot height that the detectors were approved.

Because this violation was of very low safety significance and it was entered into the licensee's CAP as CR 2011-06242 and planned to evaluate modifications to address the issue, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. **(NCV 05000440/2011005-05; Diesel Generator Rooms' Fire Protection System Concern)**

.2 <u>Pre-operational Testing of an Independent Spent Fuel Storage Facility Installation at Operating Plants</u> (60854.1)

a. <u>Inspection Scope</u>

An inspection of the licensee's control of heavy loads program that supports the initial loading of dry fuel storage canisters at the Perry Nuclear Power Plant was completed this quarter. The inspection included in-office and on-site reviews of plant design calculations including structural evaluations of the Fuel Handling Building crane and crane support structure. The inspectors reviewed structural evaluations associated with the seismic design of the trolley girder, crane bridge girders, crane earthquake restraints, floor loading in the spent fuel pool and floor loading cask placement areas in the Fuel Handling Building. Additionally, the inspectors reviewed inspection, testing, and maintenance documentation associated with the Fuel Handling Building crane and lift yoke, as well as, documentation supporting the upgrade of the Fuel Handling Building crane to Single Failure Proof in accordance with NUREG-0554.

The licensee is pursuing physical restraints during the vertical cask transfer operations in parallel with revising their free-standing analysis to ensure compliance with NRC requirements. The site anticipates providing their revised stability analyses in March 2012 at which time the NRC will conduct an inspection to ensure compliance with NRC requirements. The inspectors note that the licensee is planning to deploy additional configurations of free-standing, non-stacked casks during ISFSI loading operations within the Fuel Handling Building using similar analytical methods. Following the inspection of the stability calculations related to vertical transfer operations, the inspectors will assess the acceptability of the stability analyses of the non-stacked cask configurations as needed.

This inspection concludes the heavy loads reviews performed under IP 60854.1. The remaining balance of inspection activities performed under IP 60854.1 will continue into the next several quarters as the licensee nears their first loading campaign.

b. Findings

Failure to Perform Adequate Evaluation of Crane Support Structure Elements

Introduction: A finding of very low safety-significance and an associated NCV of 10 CFR, Part 50, Appendix B, Criterion III, “Design Control,” was identified by the inspectors for failure to have adequate design control measures for the crane support structure elements which included bridge crane rail, bridge crane rail clips, bridge crane rail clip studs, leveling plate, and leveling plate anchors. Specifically, for evaluation of these structural elements, the inspectors identified three examples where the licensee failed to demonstrate Seismic Category I compliance in accordance with their design and licensing basis and failed to evaluate the structural elements for resulting reaction forces from the Fuel Handling Building crane.

Description: The process of safely moving spent nuclear fuel from the spent fuel pool into dry storage will place heavy loads on existing structures and components that must be evaluated to ensure structural integrity when subjected to the design loads. Updated Safety Analysis Report, Section 3.8.4, titled “Other Seismic Category I Structures” provides the design and licensing basis requirements for the Fuel Handling Building. The Fuel Handling Building is a reinforced concrete structure that contains the spent fuel pool and an overhead crane that was designed to handle dry fuel storage casks. By design, the overhead crane cannot traverse the spent fuel assemblies located in the spent fuel pool. The function of the Fuel Handling Building, as stated in USAR, Section 3.8.4.1.3.1, is “to store new fuel and to receive and store spent fuel.” Table 3.2-1 of the USAR classified the Fuel Handling Building and Fuel Handling Building crane as Seismic Category I.

During review of Calculation No. 5:05.010, “Fuel Handling Bldg-Fuel Handling Area Crane Rails,” Revision 0, Addendum A01 and Addendum A02, the inspectors identified the following three examples where the licensee failed to meet the requirements in 10 CFR Part 50, Appendix B, Criterion III, “Design Control”:

1) In Calculation No. 5:05.010, Addendum A01, Revision 0, the calculations did not take into account the longitudinal seismic load along the axis of the rail for the evaluation of the bridge crane rail, rail clip, rail clips studs, leveling plate and leveling plate anchors. The longitudinal seismic load which is applied along the axis of the rail was consistent with the boundary conditions for those aforementioned structural elements established in the Fuel Handling Building Crane design basis seismic analysis located in Attachment 2 of Calculation No.SQ-194, “Seismic Qualification of the Fuel Handling Area Crane CN-25590,” Revision 1.

2) In Addendum A01 the licensee used an allowable bending stress which allowed for permanent deformation of the rail clip. Table 3.8-5 of the USAR titled, “Load Combinations for Steel Structures Outside Containment” provided allowable stress criteria for the normal, severe and extreme environmental loading conditions. The structural steel acceptance criteria were described in USAR Section 3.8.4.4 as based on the American Institute of Steel Construction (AISC) specification. Section 3.8.4.4 of the USAR states “For structural steel members the only permanent deformation allowed is in the pipe restraint collars which are designed into the plastic range.”

Also in Addendum A01 the inspectors identified that the leveling plate anchorage had an existing overstress condition (applied stress greater than allowable stress).

3) In Addendum A02 the licensee used the non-linear effects of friction to reduce the longitudinal seismic load along the axis of the rail which was applied to the rail and the leveling plate anchors. This approach was not consistent with design and licensing basis crane and crane support structure seismic analysis which were based on a linear elastic design approach and not consistent with the boundary conditions of the Fuel Handling Building crane design basis seismic analysis.

Upon identification by the inspectors, the licensee documented these deficiencies in CR 11-88791, "NRC Dry Fuel Inspection Question 170 Not Adequately Described in CR 10-86582," dated January 26, 2011; CR 11-90252, "NRC Dry Fuel Inspection Question 165 Not Specifically Described," dated February 4, 2011; CR 10-86582, "NRC Identified SFDS and FHB Calculations Lacking Details," dated December 3, 2010; and CR 11-04124, "FHB Crane Rail Anchorage calculation issues," dated October 21, 2011. The licensee initiated actions for calculation revisions as necessary.

Analysis: The inspectors determined that the failure to perform adequate evaluations to demonstrate Seismic Category I compliance was contrary to the design control measures per 10 CFR Part 50, Appendix B, requirements and was a performance deficiency.

The inspectors determined the performance deficiency affected the Barrier Integrity Cornerstone. The performance deficiency was determined to be more than minor because if left uncorrected the performance deficiency could lead to a more significant safety concern for plant equipment if Independent Spent Fuel Storage Installation (ISFSI) loading was conducted.

Specifically compliance with Seismic Category I requirements for the rail, rail clip, rail clip studs, leveling plate and leveling plate anchors was required to ensure structure integrity of structures, systems and components described in the USAR, when subjected to design loads for safe load handling of heavy loads near the spent fuel pool and integrity of the spent fuel cask. The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Phase 1 - Initial Screening and Characterization of findings," Table 4a for the Barrier Integrity cornerstone. Based on answering "No" to all the questions in the Barrier Integrity cornerstone column of Table 4a, the finding was determined to be of very low safety-significance (Green). In addition, no actual loads exceeded the design basis. The inspectors identified a Human Performance, Work Practices (H.4.c) cross-cutting aspect associated with this finding. The licensee did not ensure effective supervisory and management oversight of work activities, including contractors, such that nuclear safety was supported. Specifically, the licensee failed to have adequate oversight of design calculations and documentation for establishing structural adequacy of the rail, rail clips, rail clip bolts, leveling plate and leveling plate anchors. (H.4(c))

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, "Design Control," states, in part, that the design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculation methods, or by the performance of a suitable testing program.

Contrary to the above,

1) On March 21, 2010, in Calculation No. 5:05.010, Addendum A01, Revision 0, the inspectors determined the licensee's design control measures failed take into account the longitudinal seismic load along the axis of the rail for the evaluation of the bridge crane rail, rail clip, rail clips studs, leveling plate and leveling plate anchors. The longitudinal seismic load which is applied along the axis of the rail was consistent with the boundary conditions for those aforementioned structural elements established in the Fuel Handling Building Crane design basis seismic analysis located in Attachment 2 of Calculation No.SQ-194, Revision 1.

2) On March 21, 2010, in Calculation No. 5:05.010, Addendum A01, Revision 0, the licensee used an allowable bending stress which allowed for permanent deformation of the rail clip. Table 3.8-5 of the USAR titled, "Load Combinations for Steel Structures Outside Containment," provided allowable stress criteria for the normal, severe and extreme environmental loading conditions. The structural steel acceptance criteria were described in USAR Section 3.8.4.4 as based on the AISC specification. Section 3.8.4.4 of the USAR states "For structural steel members the only permanent deformation allowed is in the pipe restraint collars which are designed into the plastic range." Also in Addendum A01 the inspectors identified that the leveling plate anchorage had an existing overstress condition (applied stress greater than allowable stress).

3) On July 15, 2011, in Calculation No. 5:05.010, Addendum A02, Revision 0, the licensee used the non-linear effects of friction to reduce the longitudinal seismic load along the axis of the rail which was applied to the rail and the leveling plate anchors. This approach was not consistent with design and licensing basis crane and crane support structure seismic analysis which were based on a linear elastic design approach and not consistent with the boundary conditions of the Fuel Handling Building crane design basis seismic analysis.

Because this violation was of very low safety significance (Green) and it was entered into the licensee's CAP as CR 11-88791, CR 11-90252, CR 10-86582, and CR 11-04124, this violation is being treated as an NCV consistent with Section 2.3.2 of the NRC Enforcement Policy. (**NCV 05000440/2011005-06, 07200069/2010001-01, Failure to Perform Adequate Evaluation of Crane Support Structure Elements**)

4OA6 <u>Meetings</u>

.1 <u>Exit Meeting Summary</u>

On January 12, 2012, 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 confirmed that none of the potential report input discussed was considered proprietary. Proprietary material received during the inspection was returned to the licensee.

.2 Interim Exit Meetings

Interim exits were conducted for

- the emergency preparedness program inspection discussed with Mr. F. Smith on November 28, 2011;
- the licensed operator requalification training annual operating test results discussed with the Operators Training staff, Ray Torres, via telephone on December 15, 2011;
- the results of the review associated with URI 05000440/2010006-02, “Diesel Generator Rooms’ Fire Protection System Concern,” with the Design Engineering Manager, Mr. T. Hilston, on December 20, 2011;
- the ISFSI preoperational inspection on December 22, 2011, with Mr. R. Fili and other members of the licensee management and staff.

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

4OA7 Licensee-Identified Violations

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

- Technical Specification 3.0.4 for Perry requires in part that “When an LCO is not met, entry into a Mode or other specified condition in the Applicability shall only be made: when the associated Actions to be entered permit continued operation in the Mode or other specified condition in the Applicability for an unlimited period of time.” Contrary to the above, October 18, 2011, the licensed was conducting a startup and changed modes to Mode 2 when the backfeed line was not available to support the requirement of TS 3.8.1 for two offsite sources. The licensee identified that the system disconnects in the switchyard had been opened for maintenance during a forced outage and tagged out by the distribution operator through switching orders acted on by the Perry control room. The disconnects were not closed prior to the startup because the actions to do so were not tracked in the control room. The issue was documented in CR-2011-03926 and immediate actions were taken in coordination with the central dispatcher to clear the tags and close the disconnects.

  The failure to ensure on startup that the requirements for compliance with TS 3.8.1 were met on startup is a performance deficiency. The inspectors determined that the finding was more than minor because it was similar to IMC 0612, Appendix E, example 2.g in that the mode change was made without all required equipment being operable. The performance deficiency is associated with the Mitigating Systems Cornerstone attribute of Configuration Control and adversely impacted the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The finding was reviewed for significance in accordance with IMC 0609, “Significance Determination Process,” Attachment 0609.04, “Phase 1 - Initial Screening and Characterization of findings," Table 3b for the Mitigating Systems Cornerstone. The inspectors determined the finding was of very low safety significance because it was not a design/qualification deficiency, did not represent a loss of system safety function, did not result in a loss of function of a single train for greater than its TS-allowable outage time, did not result in a loss of function of nonsafety-related risk-significant equipment and was not risk-significant due to external events.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

V. Kaminskas, Site Vice President
J. Grabnar, Site Operations Director
R. Fili, Site Engineering Director
H. Hanson, Performance Improvement Director
F. Smith, Emergency Preparedness Manager
M. Stevens, Maintenance Director
J. Tufts, Operations Manager
P. Wilson, Dry Cask Storage Project

NRC

N. Valos, Senior Reactor Analyst

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened And Closed

05000440/2011005-01 and 05000440/2011005-02	SL-IV NCV	Failure To Comply With TS 5.5.11, TS Bases Control Program (Section 1R15)
05000440/2011005-03	NCV	Failure To Establish A Procedure To Perform Maintenance On Safety-Related Equipment (Section 1R15)
05000440/2011005-04	NCV	Failure To Maintain The Plant Underdrain System Within USAR Described Capabilities (Section 1R22)
05000440/2011005-05	NCV	Diesel Generator Rooms' Fire Protection System Concern (Section 4OA5.1)
05000440/2011005-06 and 07200069/2010001-01	NCV	Failure to Perform Adequate Evaluation of Crane Support Structure Elements (Section 4OA5.2)

Closed

05000440/2011-002	LER	Condition Prohibited by Technical Specifications and Plant Shutdown Due to Unit 1 Startup Transformer Issues
05000440/2011-003	LER	Switchyard Configuration During Startup Results in Operation Prohibited by Technical Specifications
05000440/2010006-02	URI	Diesel Generator Rooms' Fire Protection System Concern (Section 4OA5.1)

LIST OF DOCUMENTS REVIEWED

The following is a partial list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC 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

- NOP-WM-2001; Work Management Scheduling/Assessment/Seasonal Readiness Processes; Revision 12
- PTI-GEN-P0026; Preparations for Winter Operation; Revision 6
- PTI-GEN-P0027; Cold Weather Support System Startup; Revision 13
- Licensee List of 2011 Winter Prep Orders; dated October 10, 2011
- IOI-15; Seasonal Variations; Revision 18
- ONI-R36-2; Extreme Cold Weather; Revision 3
- CR 2011-04953; No AC Power on Freeze Protection Panel 1CCP4; dated November 5, 2011
- CR 2011-05005; Evaluate Cold Weather Impact of Door Removed from Unit 2 Turbine Power Complex; dated November 7, 2011
- CR 2011-04533; Alignment of TB Supply Plenum Drain; dated October 28, 2011

1R04 Equipment Alignment

- VLI-P45; Emergency Service Water System Valve Lineup Instruction; Revision 12
- SOI-P45/49; Emergency Service Water and Screen Wash Systems System Operating Instruction; Revision 19
- Drawing 302-0791-00000; Emergency Service Water System; Revision UU
- Drawing 302-0792-00000; Emergency Service Water System; Revision LL
- VLI-M15; Annulus Exhaust Gas Treatment System (Unit 1); Revision 4
- SOI-M15; Annulus Exhaust Gas Treatment System; Revision 10
- Drawing 912-0605-00000; Reactor Building Annulus Exhaust Gas Treatment; Revision 10
- SOI-E51; Reactor Core Isolation Cooling System; Revision 29
- VLI-E51; Valve Lineup Instruction - Reactor Core Isolation Cooling System; Revision 8
- ONI-SPI A-7; RCIC Emergency Operation; Revision 5
- EOP-SPI 2.5; Bypass of RCIC Isolations; Revision 0
- EPO-SPI 2.11; RCIC Suction Override to CST; Revision 0
- Protected Equipment Posting Checklist; RCIC Posted for LAR; dated October 10, 2011
- Drawing 302-0631-00000; Reactor Core Isolation Cooling System; Revision EE
- SOI-P42; Emergency Closed Cooling System; Revision 18
- VLI-P42; Emergency Closed Cooling System; Revision 16
- Drawing 302-0621-00000; Emergency Closed Cooling System; Revision SS
- Drawing 302-0622-00000; Emergency Closed Cooling System; Revision M
- PTI-P42-P0012; ECC System Loop A Flow Balance; Revision 6
- ELI-R24; 480 Volt MCC; Revision 26
- SOI-R43; Division 1 and 2 Diesel Generator System; Revision 38
- Drawing 302-0351-00000; Standby Diesel Generator Starting Air; Revision BB
- Drawing 302-0352-00000; Standby Diesel Generator Fuel Oil System; Revision GG
- Drawing 302-0353-00000; Standby Diesel Generator Lube Oil; Revision S
- Drawing 302-0354-00000; Standby Diesel Generator Jacket Water; Revision U

- Drawing 302-0355-00000; Standby Diesel Generator Exhaust, Intake and Crankcase; Revision W

1R05 Fire Protection (Annual/Quarterly)

- PAP-1910; Fire Protection Program; Revision 23
- FPI-1DG; Pre-Fire Plan Instruction – Diesel Generator Building; Revision 6
- Drawing 101-0064-00000; Diesel Generator Building Floor Plan Elev. 620'-6" & Elev. 646'-6"; Revision H
- FPI-0IB; Pre-Fire Plan Instruction – Intermediate Building ; Revision 6
- Drawing 101-0031-00000; Intermediate Building Floor Plan Elev. 574'-10" & Elev. 585'-0"; Revision J
- Drawing 101-0034-00000; Intermediate Building Floor Plan Elev. 639'-6" & Elev. 654'-6"; Revision F
- Drawing 101-0035-00000; Intermediate Building Floor Plan Elevation 665'-0", 682'-6", 707'-6"; Revision K
- FPI-0FH; Pre-Fire Plan Instruction – Fuel Handling Building; Revision 4
- Drawing 101-0032-00000; Intermediate Building Floor Plan Elev. 599'-0"; Revision L
- FPI-0CC; ; Pre-Fire Plan Instruction – Control Complex; Revision 8
- Drawing 105-0012-00000; Control Complex Floor Plan Elev. 599'-0"; Revision L
- Scenario #FD-1075-120111; Fire Drill Planning Guide; dated December 1, 2011
- Fire Drill Critique; dated December 1, 2011
- CR 2011-06219; Enhancements for FPI-0CC; dated December 2, 2011

1R06 Internal Flooding

- PAP-0204; Housekeeping/Cleanliness Control Program; Revision 24
- NOP-OP-1012; Material Readiness and Housekeeping Inspection Program; Revision 5
- Drawing 911-0617-00000; Auxiliary Building Drains; Revision F

1R11 Licensed Operator Requalification Program

- Simulator Exercise Guide OT-3070-RP1A; Annual Requal Exam Scenario; Revision 6
- Simulator Exercise Guide OT-3070-PC1D; Annual Requal Exam Scenario; Revision 0

1R12 Maintenance Effectiveness

- NOP-ER-3004; FENOC Maintenance Rule Program; Revision 1
- Summary of Work Orders on Unit 1 Startup Transformer from September 2010 through September 2011
- WO 200390916; (R/T) EMI Testing – U1 Startup Xfmr; dated September 29, 2011
- Summary of Condition Reports on Unit 1 Startup Transformer from September 2009 through September 2011
- Perry Nuclear Power Plant, Plant Health Report 2011-03; System – S11– Power Transformers; dated December 2, 2011
- CR 2010-82795; Unit 1 S/U XFMR Oil Analysis Results Indicate High Carbon Monoxide [CO] Gas; dated September 17, 2010
- Perry Nuclear Power Plant, Periodic Assessment of Maintenance Rule Program; Cycle 12, May 14, 2007 through May 13, 2009; dated October 8, 2010

1R13 Maintenance Risk Assessments and Emergent Work Control

- SOI-C71; RPS Power Supply Distribution; Revision 19
- CR 2011-04184; 1N25-F250A Controlling Level High in MSR 1A Second Stage Drain Tk; dated October 23, 2011
- CR 2011-04892; 2nd Stage MSR's Removed From Service Due to Drain Valve Failure; dated November 3, 2011
- WO 200480181; 1N25-F250A Maintaining Level High/CR 2011-04184; Revision 0
- WO 200481450; Replace Head Assembly for Level Transmitter 1N25N0223A; Revision 1
- CR 2011-06786; Equipment Staging for Diesel AOT May Affect Fast Firewater Alignment; dated December 13, 2011

1R15 Operability Determinations and Functionality Assessments

- PORC Minutes from Meeting of October 12, 2011, concerning RHR A Valve Lineup and System Venting
- CR-2011-02474; Restoration of the Unit 1 Startup Transformer; dated September 27, 2011
- NUREG 0887; Safety Evaluation Report Telated to the Operation of Perry Nuclear Power Plant Units 1 and 2; dated May 1982
- CR-2011-02429; Improvement Opportunity for Risk Significant System Work; dated September 26, 2011
- Change Request No. 96-109 to Technical Specification Bases; dated May 24, 1996
- Time Validation Study Memo for Placing Backfeed in Service from A.J. Okorn to E.C. William; dated May 15, 1996
- US Atomic Energy Commission Regulatory Guide 1.93; Availability of Electric Power Resources; dated December 1974
- SVI-R10-T5227; Off-site Power Availability Verification; Revision 4
- SVI-R10-T5227; Off-site Power Availability Verification; Revision 5
- Operational Decision Making Issue for CR-2011-03458; Performance of RHR A LPCI Valve Lineup Verification and System Venting Surveillance SVI-E12-T1182A; dated October 12, 2011
- 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 2011-05158; Annulus Exhaust Gas Treatment System SVI-M15T1240A 18 Mo Surveillance Test 200398453 SVI-M15-T3015 Test and Inspection Review; dated November 9, 2011
- CR 2011-05530; NRC Question on AEGTS Operability; dated November 16, 2011

1R18 Permanent/Temporary Modifications

- NOP-CC-2003; Engineering Changes; Revision 14
- NORM-CC-2001; Engineering Change Process Flowcharts; Revision 00
- ECP 11-0626-000; Reference Docs – Temporary Installation of Davis-Besse Transformer for Perry Unit 1 Startup Transformer; Revisions 0, 1, 2, and 3
- ECP 11-0626-001; Temporary Installation of Davis-Besse Transformer for Perry Unit 1 Startup Transformer; Revisions 0 through 8

1R19 Post-Maintenance Testing

- CR 2011-05180; 1C11F010 and 1C11F011 Failed Initial Stroke Time Closed During SVI-C11-T2004; dated November 10, 2011

- WO 200482050; Replace Valve and Verify Proper Opening and Closing Sequence Timing Data of Valves 1C11F0010, 1C11F0011, 1C11F0180, and 1C11F0181; Revision 0
- SVI-C11-T2004; Scram Discharge Volume Vent and Drain Valves Operability Test; Revision 18 – dated November 18, 2011
- WO 200477603; Modify SU XFMR Deluge per TM ECP 11-0632; Revision 0
- WO 200479744; Perform S/U Xfmr Testing TM 11-0626-001; Revision 0, Addendum A13
- TXI-0399; Unit 1 Startup Transformer Energized Testing; Revision 1
- TXI-0399; Unit 1 Startup Transformer Energized Testing; Revision 2
- TXI-0399; Unit 1 Startup Transformer Energized Testing; Revision 3 – Completed December 2, 2011
- Commission Testing Checklist for 100-PY-T; dated October 24, 2011
- CR 2011-05446; Issues Identified During PTI-P54-P0064 (Water Spray Flow Test for Unit 1 Startup Xfmr); dated November 15, 2011
- CR 2011-05531; Ground Alarms on Buses D1B, D2B; dated November 16, 2011
- CR 2011-05673; Re-energizing DC Power to Unit 1 Startup Transformer Causes Ground on D-1-B DC Bus; dated 2011-05673
- CR 2011-05880; UNSAT Voltage Readings While Performing TXI-0399, Unit 1 Startup Transformer Energized Testing; dated November 23, 2011
- CR 2011-05961; Unit One Startup Transformer Nitrogen Alarms Not Received By The Control Room; dated November 27, 2011
- CR 2011-06203; Low Voltages Observed When All L Buses on Unit 1 Startup Transformer; dated December 2, 2011
- WO 200481002; 7 Day Post Energized Testing on U1 S/U Xfmr; dated December 2, 2011
- WO 200477087; Perform Cable Diagnostic Withstand Test, 100-PY-B Secondary Cables; dated November 30, 2011
- CR 2011-06672; Drywell Equipment Drain Sump Rate Recorder Erratic; dated December 11, 2011
- WO 200470807; FO – HB M41 Heater Exhaust Fan 'B' Shaft Shear; Revision 0
- WO 200327449; “New PM” Replace Motor; Revision 0

1R20 Other Outage

- Perry Nuclear Power Plant Work Implementation Schedule – Unit 1 S/U Transformer Replacement Forced Outage; dated October 2, 2011
- Perry Nuclear Power Plant Work Implementation Schedule – Unit 1 S/U Transformer Replacement Forced Outage; dated October 19, 2011
- IOI-1; Cold Startup; Revision 34
- IOI-3; Power Changes; Revision 45
- IOI-4; Shutdown; Revision 17
- IOI-8; Shutdown By Manual Reactor Scram; Revision 8
- IOI-12; Maintaining Cold Shutdown; Revision 13

1R22 Surveillance Testing

- SVI-T23-T1203; Cold Shutdown Primary Containment and Drywell Integrity Verification; Revision 2 – dated October 6, 2011
- SVI-C41-T1026; Standby Liquid Control Boron Concentration; Revision 4 – dated November 3, 2011
- Computer Automated Laboratory System Detailed Sample Results for SBLC Tank [Boron Analysis]; dated November 2, 2011
- REC-0104; Chemistry Specifications; Revision 5

- CHI-0025; Boron Analysis; Revision 4
- SVI-E22-T2001; HPCS Pump and Valve Operability Test; Revision 25 – dated November 18, 2011
- SOI-E22A; High Pressure Core Spray System; Revision 30
- NOP-SS-3007; Nuclear Operating Procedure Writer's Guide; Revision 3
- PAP-0500; Perry Technical Procedure Writer's Guide; Revision 5

1EP4 Emergency Action Level and Emergency Plan Changes

- NOP-LP-5002; Evaluation of Changes to Emergency Plans and Supporting Documents 10 CFR 50.54(q); Revision 02
- EP; Emergency Plan for Perry Nuclear Power Plant; Revision 32
- EPI-A1; Emergency Action Levels; Revision 23
- EPI-B4; First Aid and Medical Care; Revision 15
- EPI-B007A; Automated Offsite Dose Calculations; Revision 13

1EP6 Drill Evaluation - Training Observation

- Simulator Exercise Guide OT-3070-PC5D; Annual Requal Exam Scenario; Revision 1; dated October 30, 2003

4OA1 Performance Indicator Verification

- NOBP-LP-4012; NRC Performance Indicators; Revision 3
- NOBP-LP-4012-10; Data Sheets for Reactor Coolant System Leakage from October 2010 to September 2011; Revision 2
- CR 2011-96024; Walkdown of the Drywell to Identify Leakage into the EDS & FDS Systems; dated June 6, 2011
- CR 2011-96083; Reactor Head Vent Line Drain Valves Leaking Past Seats; dated June 7, 2011
- CR 2011-96090; RCS Leakage – Action Level 1 (White) Threshold; dated June 7, 2011
- NOBP-LP-4012-19; MSPI Data Sheets for Emergency Service Water from July 2010 to June 2011; Revision 2
- Mitigating Systems Performance Index Basis Document; Revision 4
- Mitigating Systems Performance Index Basis Document; Revision 5
- PYBP-DES-0011; Mitigating Systems Performance Index; Revision 1
- PYBP-DES-0011; Mitigating Systems Performance Index; Revision 2
- eSOMS Narrative Logs; July 2010 to June 2011
- MSPI Derivation Reports for MSPI Monitored Systems; July 2010 to June 2011

4OA2 Problem Identification and Resolution

- NOBP-OP-0012; Operator Work-Arounds, Burdens, and Control Room Deficiencies; Revision 1
- Lotus Notes Operator Work-around/Burdens and Control Room Deficiency Database, Selected Entries from January 2010 through October 2011
- CR 2011-00281; Div 1 DG Jacket Water High Temperature Alarm, Increased Frequency; dated August 7, 2011
- CR 2011-01579; Division 2 Diesel Generator Air Dryer 1R44D0002B Does Not Have Adequate Dewpoint Indicated for PTI-R44-P00001B; dated September 5, 2011
- CR 11-97550; Tracking of Ops Burdens & Control Room Deficiencies

- CR 2011-05598; Operator Work Arounds/Burdens/Deficiencies Impact on the BOP Control Room Operator; dated November 17, 2011
- Control Room Deficiencies, Operator Burdens, and Operator Workarounds; dated October 3, 2011
- Control Room Deficiencies, Operator Burdens, and Operator Workarounds; dated December 19, 2011
- Monthly Performance Report – Operational Focus Index; dated November 2011
- CR 2011-03926; Discovered S-610 and S-611 Bounding Disconnects Danger Tagged Open by Northern Region; dated October 18, 2011
- Operations Night Order; Switchyard Clearance and Switching Orders; dated October 19, 2011
- Human Performance Success Clock Evaluation Results; dated November 4, 2011

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

- 50.72 Event Report for Shutdown Required by Technical Specifications Due to Transformer Fault; dated October 2, 2011
- LER 2011-002-00; Condition Prohibited by Technical Specifications and Plant Shutdown Due to Unit 1 Startup Transformer Issues; dated November 22, 2011
- LER 2011-003-00; Switchyard Configuration During Startup Results in Operation Prohibited by Technical Specifications; dated December 15, 2011

4OA5 Other Activities

- CR 10-81513; NRC Has Questioned Use of a Load Factor in Table 3.8-6 of the USAR; dated August 13, 2010
- CR 10-82352; NRC ID Issues with Dry Fuel Storage Calc G58-S-SC-002 Add 1, Rev 0; dated September 8, 2010
- CR 10-86582; NRC Identified SFDS and FHB Calculations Lacking Details; dated December 3, 2010
- CR 11-88791; NRC Dry Fuel Inspection Question 170 not Adequately Described in CR 10--86582; dated January 26, 2011
- CR 11-88795; NRC Dry Fuel Questions 37 and 157 Steel Rail and ZPT Roller Failure Evaluation; dated January 26, 2011
- CR 11-88808; NRC Inspection Question 275 Use of AISE Standard Contrary to AISC 7th Edition; dated January 26, 2011
- CR 11-88898; NRC Dry Fuel Inspection Questions 218, 227, 229, 271 & 272 Issues; dated January 27, 2011
- CR 11-88899; NRC SFDS Inspection Questions 219, 220, 221, 224 and 270 for Spent Fuel Pool Design; dated January 27, 2011
- CR 11-88906; NRC Dry Fuel Inspection Questions 265, 267, 268 and 269 Resolutions; dated January 28, 2011
- CR 11-90252; NRC Dry Fuel Inspection Question 165 Not Specifically Described; dated February 4, 2011
- CR 11-91769; NRC Spent Fuel Dry Storage Questions 252, 258 and 259; dated March 25, 2011
- CR 11-97578; Calculation SQ-0194 Clarification; dated July 12, 2011
- CR 11-04124; FHB Crane Rail Anchorage calculation issues; dated October 21, 2011
- CR 11-04122; Calculation clarification for localized yielding; dated October 21, 2011

- Calculation No. 5:05.010; Fuel Handling Bldg-Fuel Handling Area Crane Rails, Revision 0, Addendum A01; dated March 21, 2010
- Calculation No. 5:05.010; Fuel Handling Bldg-Fuel Handling Area Crane Rails, Revision 0, Addendum A02; dated July 15, 2011
- Calculation No. 5:05.010; Fuel Handling Bldg-Fuel Handling Area Crane Rails, Revision 0; dated July 28, 1980
- Calculation No. SQ-194; Seismic Qualification of the Fuel Handling Area Crane CN-25590, Revision 1, Addendum A-01; dated August 22, 2011
- Calculation No. SQ-194; Seismic Qualification of the Fuel Handling Area Crane CN-25590, Revision 1; dated May 11, 2011
- Calculation No. 5:05.09.04; Fuel Handling Bldg Walls EL620-6 to EL682-6 Wall Design, Revision 1; dated July 14, 2011
- Calculation No. G58-S-R-L-006; NUREG-554 Conformance Matrix for Fuel Handling Area Crane, Revision 0; dated August 5, 2010
- CR 2011-06242; NRC CDBI 2011- Potential Green Non-Cited Violation (NCV); December 2, 2011
- P54-208; Response Calculation for the Carbon Dioxide System Heat Detectors in the Emergency Diesel Generator Rooms; Revision 0
- P54-208; Response Calculation for the Carbon Dioxide System Heat Detectors in the Emergency Diesel Generator Rooms; Revision 1
- P54-208; Response Calculation for the Carbon Dioxide System Heat Detectors in the Emergency Diesel Generator Rooms; Revision 2
- WO 860016030; Replace 12 Heat Detectors (DCP 86-667); Revision 0
- WO 200194345; Upgrade CO2 Fire Protection Panel; Revision 1

<u>4OA7 Licensee-Identified Violation</u>

- CR 2011-03926; Discovered S-610 & S-611 Bounding Disconnects Danger Tagged Open by Northern Region

LIST OF ACRONYMS USED

AEGTS	annulus exhaust gas treatment system
ADAMS	Agencywide Document Access Management System
AISC	American Institute of Steel Construction
CAP	corrective action program
CDF	core damage frequency
CR	Condition Report
CFR	*Code of Federal Regulations*
EDG	emergency diesel generator
FDS	fire damage state
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Inspection Report
ISFSI	Independent Spent Fuel Storage Installation
ISLOCA	inter-system loss-of-coolant accident
LCO	limiting condition for operation
LER	Licensee Event Report
LERF	large early release frequency
LOCA	loss-of-coolant accident
LOOP	loss of offsite power
MSPI	mitigating systems performance index
NCV	non-cited violation
NEI	Nuclear Energy Institute
NFPA	National Fire Protection Association
NRC	Nuclear Regulatory Commission
PI	performance indicator
RCS	reactor coolant system
SBO	station blackout
SDP	Significance Determination Process
SPAR	standardized plant analysis risk
SRA	senior reactor analyst
SUT	startup transformer
TS	Technical Specification
URI	unresolved item
USAR	Updated Safety Analysis Report
°F	degrees Fahrenheit

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 (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/

John B. Giessner, Chief
Branch 4
Division of Reactor Projects

Docket No. 50-440; 72-069
License No. NPF-58

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Letter to V. Kaminskas from J. Giessner dated February 6, 2012.

SUBJECT: PERRY NUCLEAR POWER PLANT - NRC INTEGRATED INSPECTION REPORT 05000440/2011005 (DRP) AND 07200069/2010001 (DNMS)

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