February 12, 2008

EA-07-199

Mr. Barry S. Allen
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 05000440/2007005

Dear Mr. Allen:

On December 31, 2007, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Perry Nuclear Power Plant. The enclosed report documents the inspection findings which were discussed on January 10, 2008, 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. In addition, it has been determined that Perry is in the Regulatory Response column of the Action Matrix (as outlined in our letter to you of May 8, 2007). In December of 2007, the NRC reviewed Perry operational performance, inspection findings, and performance indicators for the third quarter of 2007. Based on this review, we concluded that Perry was operating safely. However, the inspectors noted that performance indicator status for unplanned scrams remained under evaluation. The characterization of two scram events that occurred in June 2007 was under review using the NRC Frequently Asked Questions process, and the outcome of this process had the potential to affect the color of the unplanned scram performance indicator.

Based on the results of this inspection, four NRC-identified and three self-revealed findings of very low safety significance were identified. Six of the findings identified also involved violations of NRC requirements. In addition, one NRC-identified non-cited violation of NRC requirements, without an associated finding, was identified. However, because the findings associated with these violations were of very low safety significance and because the issues were entered into your corrective action program, the NRC is treating these issues as Non-Cited Violations in accordance with Section VI.A.1 of the NRC's Enforcement Policy. Additionally, two licensee identified violations are listed in Section 4OA7 of this report.

If you contest the subject or severity of any Non-Cited Violation in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, U.S. Nuclear

Regulatory Commission, Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspectors' Office 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 and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

***/RA/***

Bruce Burgess, Chief
Branch 6
Division of Reactor Projects

Docket No.: 50-440
License No.: NPF-58

Enclosure: Inspection Report 05000440/2007005
w/Attachment: Supplemental Information

cc w/encl: J. Hagan, President and Chief Nuclear Officer – FENOC
J. Lash, Senior Vice President of Operations and Chief Operating Officer – FENOC
D. Pace, Senior Vice President, Fleet Engineering – FENOC
J. Rinckel, Vice President, Fleet Oversight – FENOC
Director, Fleet Regulatory Affairs – FENOC
Manager, Fleet Licensing – FENOC
Manager, Site Regulatory Compliance – FENOC
D. Jenkins, Attorney, FirstEnergy Corp.
Public Utilities Commission of Ohio
Ohio State Liaison Officer
R. Owen, Ohio Department of Health

Regulatory Commission, Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspectors' Office 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 and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

*/RA/*

Bruce Burgess, Chief
Branch 6
Division of Reactor Projects

Docket No.: 50-440
License No.: NPF-58

Enclosure: Inspection Report 05000440/2007005
w/Attachment: Supplemental Information

cc w/encl: J. Hagan, President and Chief Nuclear Officer – FENOC
J. Lash, Senior Vice President of Operations and Chief Operating Officer – FENOC
D. Pace, Senior Vice President, Fleet Engineering – FENOC
J. Rinckel, Vice President, Fleet Oversight – FENOC
Director, Fleet Regulatory Affairs – FENOC
Manager, Fleet Licensing – FENOC
Manager, Site Regulatory Compliance – FENOC
D. Jenkins, Attorney, FirstEnergy Corp.
Public Utilities Commission of Ohio
Ohio State Liaison Officer
R. Owen, Ohio Department of Health

DOCUMENT NAME: G:\PERRY\PERR 2007 005.DOC
☐ Publicly Available ☐ Non-Publicly Available ☐ Sensitive ☐ Non-Sensitive
**To receive a copy of this document, indicate in the concurrence box "C" = Copy without attach/encl "E" = Copy with attach/encl "N" = No copy**

| OFFICE | RIII | | RIII | | RIII | | RIII | |
|---|---|---|---|---|---|---|---|---|
| NAME | GWright:cms | | BBurgess | | | | | |
| DATE | 2/11/08 | | 2/12/08 | | | | | |

***OFFICIAL RECORD COPY***

Letter to B. Allen from B. Burgess dated February 12, 2007

SUBJECT: PERRY NUCLEAR POWER PLANT NRC INTEGRATED INSPECTION REPORT 05000440/2007005

DISTRIBUTION:
RAG1
TEB
TJW2
RidsNrrDirsIrib
MAS
KGO
JKH3
MEF1
CAA1
LSL (electronic IR's only)
C. Pederson, DRP (hard copy - IR's only)
DRPIII
DRSIII
PLB1
TXN
ROPreports@nrc.gov (inspection reports, final SDP letters, any letter with an IR number)

## TABLE OF CONTENTS

U.S. NUCLEAR REGULATORY COMMISSION

REGION III

| | |
|---|---|
| Docket No: | 50-440 |
| License No: | NPF-58 |
| Report No: | 050000440/2007005 |
| Licensee: | FirstEnergy Nuclear Operating Company (FENOC) |
| Facility: | Perry Nuclear Power Plant, Unit 1 |
| Location: | Perry, Ohio |
| Dates: | October 1, 2007 through December 31, 2007 |
| Inspectors: | M. Franke, Senior Resident Inspector<br>M. Wilk, Resident Inspector<br>J. Robbins, Reactor Engineer<br>T. Taylor, Reactor Engineer<br>R. Jickling, Sr. Emergency Preparedness Analyst<br>M. Phalen, Health Physicist<br>J. Cassidy, Health Physicist<br>M. Bielby, Senior Operations Engineer<br>R. Jickling, Sr. Emergency Preparedness Analyst<br>D. Reeser, Operations Engineer |
| Observer: | J. Quichocho, Health Physicist -<br>Office of Nuclear Reactor Regulation<br>R. Leidy, Health Physicist - Ohio Department of Health<br>Terry McCall, Health Physicist - Ohio Department of Health |
| Approved by: | Bruce Burgess, Chief<br>Branch 6<br>Division of Reactor Projects |

Enclosure

## SUMMARY OF FINDINGS

IR 05000440/2007005; 10/01/2007 – 12/31/2007; Perry Nuclear Power Plant; Equipment Alignment; Post-Maintenance Testing; ALARA Planning and Controls; Problem Identification and Resolution; Other Activities.

The inspection was conducted by resident inspectors and regional emergency preparedness and health physics inspectors. The report covers a 3-month period of resident inspection. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609 “Significance Determination Process” (SDP). Findings for which the SDP does not apply may be "Green," or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated July 2006.

### A. Inspector-Identified and Self-Revealed Findings

**Cornerstone: Barrier Integrity**

- Green. A finding of very low safety significance was self-revealed on October 18, 2007, when a fuel channel dislodged from a grapple during movement in the spent fuel pool. The licensee implemented a design change to the spent fuel handling bridge grapple system that resulted in an inadequate method of verification for grapple attachment to the fuel channel. The fuel channel was inadequately attached to the grapple and dropped onto several spent fuel assemblies. As part of their immediate corrective actions, licensee personnel reinstated the previous grapple design that allowed for positive visual verification of grapple attachment and entered the issue into the corrective action program.

  The finding was more than minor because it was associated with the design control attribute of the reactor safety Barrier Integrity Cornerstone and affected the cornerstone objective of providing reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. The finding resulted in an event that challenged spent fuel cladding barrier. Although not suitable for Significance Determination Process review, the finding was determined to be of very low safety significance because the dropped fuel channel did not cause damage to the spent fuel. The primary cause of this finding was related to the cross-cutting area of Human Performance per IMC 0305 H.2(d) because the organization failed to ensure that equipment, including physical improvements, was adequate to assure nuclear safety. (Section 4OA2.4)

**Cornerstone: Mitigating Systems**

- Green. The inspectors identified a finding of very low safety significance and a non-cited violation of Technical Specification 5.4, “Procedures,” during an inspection of the reactor core isolation cooling (RCIC) system on December 12, 2007. The inspectors observed scaffold construction in the RCIC pump room that was attached to a safety-related RCIC waterleg pump structural support and to the pump base, and was in contact with small diameter waterleg pump piping. The scaffold construction was determined to be contrary to seismic clearance procedural requirements. As part of their immediate corrective actions, licensee personnel removed the affected scaffolding from the RCIC system.

The finding was more than minor because it was associated with the Protection Against External Factors attribute of the Mitigating Systems Cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events in order to prevent undesirable consequences. Specifically, the finding was determined to have placed RCIC in an unacceptable seismic configuration. The finding was determined to be of very low safety significance because it was determined not to represent a loss of safety function. The primary cause of this finding was related to the cross-cutting area of Human Performance per IMC 0305 H.3(a), because the licensee failed to appropriately plan the scaffold work activity by not incorporating the affect on plant structures, systems and components. (Section 1R04.1)

- Green. The inspectors identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," during an inspection of the reactor core isolation cooling (RCIC) system. On December 12, 2007, the inspectors observed conditions adverse to quality associated with scaffold, erected on October 31, contact affecting the RCIC system. In response to the inspectors' observations, licensee personnel investigated the RCIC room and documented that no issues with scaffold associated with the RCIC system were identified. On December 14, 2007, the inspectors accompanied licensee personnel to the RCIC pump room to point out the conditions. The licensee determined that the conditions were unacceptable and, as part of their immediate corrective actions, licensee personnel removed the scaffold from the RCIC area.

  The primary cause of this non-cited violation was related to the cross-cutting area of Problem Identification and Resolution per IMC 0305, P.2(b) because the licensee failed to implement and institutionalize internal operating experience through changes in station processes and procedures. (Section 1R04.2)

- Green. The inspectors identified a finding of very low safety significance and a non-cited violation of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," during an inspection of reactor core isolation cooling (RCIC) system testing between December 8 and December 9, 2007. The testing did not adequately incorporate requirements contained in design documents. The inspectors noted: (1) licensee personnel performed a test and later determined that the test was inappropriate; (2) personnel failed to control a test and exceeded a system design limit; and (3) personnel failed to control system configuration during testing. As part of their immediate corrective actions, operators restored the RCIC system to a normal configuration and performed an evaluation to determine whether system damage had occurred.

  The finding was considered more than minor because it was associated with the Procedure Quality attribute of the Mitigating Systems Cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events in order to prevent undesirable consequences. Specifically, the failure to properly control the testing caused the system piping design pressure limit to be exceeded. The finding was determined to be of very low safety significance because it did not represent a loss of safety function. The primary cause of this finding was related to the cross-cutting area of Human Performance per IMC 0305 H.3(a), because the licensee failed to appropriately plan work activities by incorporating planned contingencies, compensatory actions, and abort criteria. (Section 1R19)

- <u>Green</u>. The inspectors identified a finding of very low safety significance and a non-cited violation of 10 CFR 50 Appendix B, Criterion XVI, "Corrective Action," when a nonconforming condition associated with the Division 1 Emergency Diesel Generator was discovered on November 16, 2007. One cylinder head stud was torqued below the minimum required torque setting. The inspectors determined that the licensee failed to perform an appropriate extent-of-condition review when several cylinder head studs were found below minimum torque level on November 13, 2006. Also, the licensee did not perform an extent-of-condition review during a subsequent refueling outage when both emergency diesel generators were available for maintenance. As part of its immediate corrective actions, the licensee entered the issue into the corrective action program.

  The finding was more than minor because it was associated with the Equipment Performance attribute of the Reactor Safety Mitigating Systems Cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the finding addressed a lack of timely corrective action that adversely impacted the amount of time that the emergency diesel generator was subject to a degraded condition. The finding was determined to be of very low safety significance because it was determined not to represent a loss of operability. The primary cause of this finding was related to the cross-cutting area of Problem Identification and Resolution per IMC 0305 P.1(d) because the licensee failed to take appropriate corrective action to address safety issues in a timely manner. (Section 4AO2.3)

- <u>Green</u>. A finding of very low safety significance and an associated non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions," was self-revealed on July 11, 2007, when the licensee failed to assure that deficiencies associated with alternate decay heat removal capability were corrected in a timely manner. Technical Specification (TS) 3.4.10 required the licensee to verify the availability of an alternate method of decay heat removal when a residual heat removal shutdown cooling subsystem was inoperable. On May 23, 2004, the licensee was unable to meet this requirement due to the lack of an approved alternate decay heat removal system. On July 11, 2007, operators were again unable to meet TS requirements because the lack of an alternate decay heat removal system deficiency had not been corrected. As part of their immediate corrective actions, the licensee entered the issue into their corrective action program and planned to complete a design change to install an alternate decay heat removal system.

  This finding was more than minor because it was related to the Equipment Performance attribute of the Mitigating System Cornerstone and affected the cornerstone objective to ensure the availability of a mitigating system that responds to initiating events to prevent undesirable consequences. Specifically, the finding affected the availability of a decay heat removal system. Although not suited for Significance Determination Process review, the finding was determined to be of very low safety significance because the licensee restored shutdown cooling within two hours and the plant remained in Mode 4. The primary cause of this finding was related to the cross-cutting area of Human Performance per IMC 0305 H.2(a), because the licensee failed to minimize long-standing equipment issues and maintenance deferral. (Section 4OA3.1)

- Green. A finding of very low safety significance and a non-cited violation of Technical Specification 5.4, “Procedures,” was self-revealed when a loss of cooling water flow to the reactor occurred while the reactor was shutdown on July 11, 2007. A maintenance technician failed to adhere to procedures while performing a surveillance test and performed an action that caused the ‘B’ residual heat removal pump to trip. The ‘B’ residual heat removal pump was providing cooling water flow to the reactor when the pump trip occurred. As part of their immediate corrective actions, licensee personnel restored shutdown cooling water flow to the reactor by placing the ‘A’ residual heat removal loop in service and entered the issue into the corrective action program.

  The finding was more than minor because it was associated with the Equipment Performance attribute of the Initiating Events Cornerstone and affected the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, the finding resulted in a disruption of reactor decay heat removal while the reactor was shutdown. The finding was determined to be of very low safety significance after a Phase 3 Significance Determination Process review. The primary cause of this finding was related to the cross-cutting area of Human Performance per IMC 0305 H.3(b) because the organization failed to keep personnel apprised of plant conditions that affect the work. (Section 4OA5.1)

**Cornerstone: Occupational Radiation Safety**

- Green. The inspectors identified a finding of very low safety significance and a non-cited violation of Technical Specification 5.4.1.a was for the failure to adequately implement radiological dose controls as a result of ineffective radiological/As-Low-As-Is-Reasonably-Achievable (ALARA) planning and control during Refueling Outage Number 11. The total sum of the occupational radiation doses (collective dose) received by individuals for certain work activities was found in excess of that collective dose planned or intended (i.e., that dose the licensee determined was ALARA for those work activities). Corrective actions included the assignment of high impact teams to address and evaluate lessons learned from the refuel outage.

  The finding was more than minor because the finding was associated with the Occupational Radiation Safety Cornerstone attribute of ALARA planning/dose projection, and affected the cornerstone objective of programs and processes for ensuring adequate protection of worker health and safety from exposure to radiation. The finding did not involve: (1) an overexposure; (2) a substantial potential for an overexposure; or (3) an impaired ability to assess dose. It did involve ALARA planning and controls; however, the 3-year rolling average for Perry station is less than the Significance Determination Process (SDP) threshold of 240-person-rem for boiling water reactors. Consequently, the inspectors concluded through the SDP assessment that this is a finding of very-low-safety significance. The finding was determined to be associated with a cross-cutting aspect in the area of Human Performance per IMC 0305 H.3(a) in work controls. (Section 2OS2.3)

## B. Licensee-Identified Violations

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

## REPORT DETAILS

### Summary of Plant Status

The plant began the inspection period at 100 percent power. On October 14, 2007, reactor power was reduced to 76 percent for turbine valve testing and to effect repairs to the 'B' reactor feedwater pump turbine. Reactor power was returned to 100 percent on the same day. On October 25, 2007, operators reduced reactor power to about 95 percent in response to a failure of a hot surge tank level control valve. Following repairs, operators returned power to 100 percent on the same day. On November 28, 2007, at 7:32 a.m., the reactor scrammed due to a digital feedwater control system failure and the plant entered Mode 4 at 5:57 p.m. on the same day. The reactor was restarted on December 6, 2007, and the plant reached Mode 1 at 10:03 p.m. on December 7, 2007. Turbine generator synchronization to the grid was delayed due to equipment issues associated with a main generator output disconnect switch. Following repair to the main generator switch, synchronization to the grid occurred at 4:41 a.m. on December 10, 2007, and 100 percent power was achieved at 10:40 p.m. on December 13, 2007.

### 1. REACTOR SAFETY

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

1R04 Equipment Alignment (71111.04)

a. Inspection Scope

The inspectors conducted a partial walkdown of the following systems to determine whether the system was correctly aligned to perform its designed safety function. The inspectors used valve lineup instruction (VLIs) and system drawings during the walkdown. The walkdown included selected switch and valve position checks, and verification of electrical power to critical components. Finally, the inspectors evaluated other elements, such as material condition, housekeeping, and component labeling. The documents used for the walkdown are listed in the attached List of Documents Reviewed.

The following partial system walkdowns represent three quarterly inspection samples:

- reactor core isolation cooling (RCIC);
- annulus exhaust gas treatment system (AEGTS) 'B'; and
- emergency service water (ESW) 'C'

b. Findings

1. Introduction: The inspectors identified a Green finding of very low safety significance and a non-cited violation (NCV) of Technical Specification (TS) 5.4, "Procedures," during an inspection of the RCIC system on December 12, 2007. The inspectors observed scaffold construction in the RCIC pump room that was contrary to licensee procedures addressing seismic clearance requirements for scaffolding.

Description: On December 12, 2007, the inspectors performed a walkdown of the RCIC system. While in the RCIC pump room, the inspectors observed scaffold construction that occupied most of the north wall of the pump room. The inspectors observed that this scaffold construction was attached to a safety-related RCIC waterleg pump structural support; was attached to the pump base; and was in contact with small diameter waterleg pump piping.

The inspectors reviewed the scaffold erection checklist associated with the affected scaffold and noted that it had been initialed by licensee personnel for compliance with seismic bracing criteria in accordance with General Civil Instruction (GCI)-0016, "Scaffolding Erection, Modification or Dismantling Guidelines," Revision 9. However, the inspectors noted that GCI-0016, Section 10, "Plant Equipment Protection," stated that, "unless specifically approved by this instruction, scaffolds shall not be connected to, or in contact with any plant equipment, piping, conduits, cable trays, HVAC supports unless approved by an engineering document." Section 5.5 of GCI-0016, "Seismic Safety Area Bracing and Clearance Requirements," required a minimum of three inches clearance to all safety-related items. GCI-0016 provided an exception for contact with larger steel pipes (greater than two inches in diameter). The inspectors noted that the affected RCIC piping was less than two-inch diameter piping and that the procedure did not provide an allowance for contact with system valves. The inspectors noted that no engineering evaluation was performed to address the seismic clearance issues.

Based on the observations, the inspectors determined that licensee personnel failed to adhere to procedure GCI-0016 during the installation of the scaffold.

Analysis: The inspectors determined that the failure to adhere to scaffold procedures affecting the RCIC system was a performance deficiency warranting a significance evaluation. The inspectors concluded that the finding was greater than minor in accordance with Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports," dated September 20, 2007. It was greater than minor because it was associated with the Protection Against External Factors attribute of the Mitigating Systems Cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events in order to prevent undesirable consequences. Specifically, the finding was determined to have resulted in a degraded seismic configuration for the RCIC system.

The inspectors performed a significance determination of this issue using IMC 0609, "Significance Determination Process," dated November 22, 2005, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations," dated March 23, 2007. The finding was of very low safety significance because it did not result in an actual loss of safety function. The primary cause of this finding was related to the cross-cutting area of Human Performance per IMC 0305 H.3(a) because the licensee failed to appropriately plan the scaffold work activity by incorporating the affect on plant structures, systems and components.

Enforcement: Technical Specification 5.4, "Procedures," required the implementation of the applicable procedures recommended in Regulatory Guide 1.33, "Quality Assurance Program Requirements," Revision 2, dated February 1978. Regulatory Guide 1.33, Appendix A, stated, "Maintenance that can affect the performance of safety-related equipment should be properly preplanned and performed in accordance with written procedures appropriate to the circumstances." Licensee procedure GCI-0016, Section 10, "Plant Equipment Protection," stated that, "unless specifically approved by this instruction, scaffolds shall not be connected to, or in contact with any plant equipment, piping, conduits, cable trays, HVAC supports unless approved by an engineering document." Contrary to this requirement, on December 12, 2007, the inspectors identified that licensee personnel had placed scaffold in contact with the safety-related RCIC system in a manner that was not specifically approved by GCI-016. However, because of the very low safety significance of the issue and because the issue has been entered into the licensee's corrective action program as Condition Report (CR) 07-31437, the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy. (NCV 05000440/2007005-01)

2. Introduction: The inspectors identified an NCV of 10 CFR Part 50, Appendix B, Criterion XVI, during an inspection of the RCIC system. Between October 31 and December 14, 2007, licensee personnel failed to identify conditions adverse to quality associated with scaffolding affecting the RCIC system despite reasonable opportunities to do so.

Description: On December 12, 2007, the inspectors performed a walkdown of the RCIC system and observed scaffolding attached or in contact with a RCIC system waterleg pump structural support; the waterleg pump base; and a valve and one-inch diameter pipe connected to the suction line. The inspectors reported the conditions to the licensee on the same day.

On the following day, the inspectors noted that licensee personnel had inspected the RCIC room for the scaffold condition and had reported that no scaffolding was in contact with the RCIC pump.

On December 14, 2007 the inspectors accompanied the system engineering supervisor to the RCIC pump room to point out the scaffold affecting RCIC components that were contrary to seismic clearance. The licensee determined that the condition required repair, and licensee personnel removed the scaffold from the RCIC system.

The inspectors noted that RCIC had failed to function as designed during a November 28, 2007, scram event. Because RCIC had failed, licensee personnel had conducted walkdowns of the system between November 28, 2007 and December 14, 2007 and the system was the subject of greater-than-normal licensee review.

The scaffold that occupied most of the north wall of the RCIC pump room was large in size and was considered readily visible by the inspectors in the pump room. The inspectors determined that the scaffold contact points with the RCIC system were also readily visible during their walkdown of the system on December 12, 2007. Due to the relative ease of discovery, the inspectors determined that the licensee had reasonable opportunity to identify the condition during daily equipment walkdowns after scaffold construction on October 31, 2007, and during system alignment walkdowns that were conducted after the November 28, 2007, failure of the RCIC system. In particular, the inspectors determined that the licensee had reasonable opportunity to identify the condition during licensee walkdowns of the RCIC system after inspectors informed the licensee of the specific conditions on December 12, 2007, and then again on December 13, 2007.

Analysis: The primary cause of this finding was related to the cross-cutting area of Problem Identification and Resolution per IMC 0305 P.2(b) because the licensee failed to implement and institutionalize internal operating experience through changes in station processes and procedures. In 2005, the NRC identified programmatic deficiencies associated with the licensee's scaffold erection processes affecting safety related equipment. The issue was described in NCV 05000440/2005002-02, "Failure To Follow Procedures for Scaffold Construction in Safety-Related Areas." The inspectors determined that the scaffold issues affecting RCIC were representative of a failure to adequately implement and institutionalize process and procedure changes to address the deficiencies identified in 2005.

Enforcement: Criterion XVI, "Corrective Action," of 10 CFR 50 Appendix B, states that measures shall be established to assure that conditions adverse to quality, such as deficiencies and nonconformances are promptly identified and corrected. Contrary to this requirement, between October 31, 2007, and December 14, 2007, licensee personnel failed to promptly identify conditions adverse to quality associated with the safety-related RCIC system. However, because of the very low safety significance of the issue and because the issue has been entered into the licensee's corrective action program (CR 07-31437), the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy. (NCV 05000440/2007005-02)

## 1R05 Fire Protection (71111.05)

### a. Inspection Scope

The inspectors walked down the following areas to assess the overall readiness of fire protection equipments and barriers:

- Fire Zone 1DG-1a, Division 2 EDG;
- Turbine Power Complex Building;
- Fire Zone 1CC-3D, Unit 1 Remote Shutdown Panel Room;
- Fire Zone 1AB-1C, Reactor Core Isolation Cooling pump room;
- Fire Zone XFMR, Transformer Yard Areas;
- Fire Zone 1DG-1B, Unit 1 Division 3 Diesel Generator Building;
- Fire Zone 0EW-1A, Emergency Service Water Pumphouse; and
- Fire Zone 0FH, Fuel Handling Building.

Emphasis was placed on evaluating the licensee's control of transient combustibles and ignition sources, the material condition of fire protection equipment, the material condition and operational status of fire barriers used to prevent fire damage or propagation. The inspectors utilized the general guidelines established in Fire Protection Instruction (FPI)-A-A02, "Periodic Fire Inspections," Revision 5; Perry Administrative Procedure (PAP)-1910, "Fire Protection Program," Revision 15; and PAP-0204, "Housekeeping/Cleanliness Control Program," Revision 18; as well as basic National Fire Protection Association Codes, to perform the inspection and to determine whether the observed conditions were consistent with procedures and codes.

The inspectors observed fire hoses, sprinklers, and portable fire extinguishers to determine whether they were installed at their designated locations, were in satisfactory physical condition, and were unobstructed. The inspectors also evaluated the physical location and condition of fire detection devices. Additionally, passive features such as fire doors, fire dampers, and mechanical and electrical penetration seals were inspected to determine whether they were in good physical condition. The documents listed in the List of Documents Reviewed at the end of this report were used by the inspectors during the inspection of this area.

This review represented eight quarterly inspection samples.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

The inspectors reviewed the licensee's flooding mitigation plans and equipment to determine consistency with design requirements and the risk analysis assumptions related to internal flooding. Walkdowns and reviews performed considered design measures, seals, drain systems, contingency equipment condition and availability of temporary equipment and barriers, performance and surveillance tests, procedural adequacy, and compensatory measures. The areas inspected for internal flooding were:

- RCIC pump room; and
- reactor water cleanup pump rooms.

This review represented two quarterly internal inspection samples.

b. Findings

No findings of significance were identified.

1R07 Heat Sink (71111.07)

a. Inspection Scope

The inspectors reviewed the licensee's testing of Division 2 EDG heat exchangers to verify that any potential deficiencies did not mask the licensee's ability to detect degraded performance, to identify any common cause issues that had the potential to increase risk, and to ensure that the licensee was adequately addressing problems that could result in initiating events that would cause an increase in risk. The inspectors reviewed the licensee's observations as compared against acceptance criteria, the correlation of scheduled testing and the frequency of testing, and the impact of instrument inaccuracies on test results. Inspectors also verified that test acceptance criteria considered differences between test conditions, design conditions, and testing criteria.

This review represented one annual inspection sample.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11Q)

a. Inspection Scope

On December 17, 2007, the resident inspectors reviewed licensed operator performance in the plant simulator. The inspectors evaluated crew performance in the areas of:

- clarity and formality of communication;
- ability to take timely action in the safe direction;
- prioritizing, interpreting, and verifying alarms;
- correct use and implementation of procedures, including alarm response procedures;
- timely control board operation and manipulation, including high-risk operator actions; and
- group dynamics.

This review represents one quarterly inspection sample.

b. Findings

No findings of significance were identified.

1R11 Biennial Licensed Operator Requalification (71111.11B)

a. Inspection Scope

The inspectors reviewed the overall pass/fail results of the comprehensive annual job performance measure operating tests and the annual simulator operating tests (required to be given per 10 CFR 55.59(a)(2)) administered by the licensee during the biennial licensed operator requalification program examinations conducted in November and December 2007. The overall results were compared with the SDP in accordance with IMC 0609, Appendix I, "Operator Requalification Human Performance Significance Determination Process (SDP)."

This review represents one biennial inspection sample.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed the licensee's implementation of the maintenance rule requirements to determine whether component and equipment failures were identified and scoped within the maintenance rule and that select structures, systems, and components were properly categorized and classified as (a)(1) or (a)(2) in accordance with 10 CFR 50.65. The inspectors reviewed station logs, maintenance work orders (WOs), selected surveillance test procedures, and a sample of CRs to determine whether the licensee was identifying issues related to the maintenance rule at an appropriate threshold and that corrective actions were appropriate. Additionally, the inspectors reviewed the licensee's performance criteria to determine whether the criteria adequately monitored equipment performance and to determine whether changes to performance criteria were reflected in the licensee's probabilistic risk assessment. During the inspection period the inspectors reviewed the following systems:

- Service air and instrument air systems;
- fuel handling building refueling bridge and associated systems; and
- RCIC

These maintenance effectiveness reviews constituted three inspection samples.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors reviewed the licensee's evaluation of plant risk, scheduling, configuration control, and performance of maintenance associated with planned and emergent work activities to determine whether scheduled and emergent work activities were adequately managed in accordance with 10 CFR 50.56(a)(4). In particular, the inspectors reviewed the licensee's program for conducting maintenance risk assessments to determine whether the licensee's planning, risk management tools, and the assessment and management of on-line risk were adequate. The inspectors also reviewed licensee actions to address increased on-line risk when equipment was out of service for maintenance, such as establishing compensatory actions, minimizing the duration of the activity, obtaining appropriate management approval, and informing appropriate plant staff, to determine whether the actions were accomplished when on-line risk was increased due to maintenance on risk-significant structures, systems, and components. The following assessments and/or activities were reviewed and represented a total of five samples:

- Division 2 EDG maintenance during the week of October 9, 2007;
- LH20 electrical bus outage during the week of October 9, 2007;
- Feedwater ‘A’ Venturi maintenance during the week of October 15, 2007;
- Division 1 EDG maintenance outage during the week of November 5, 2007; and
- Control Rod Drive Mechanism (CRDM) 42-31 repair during the week of December 3, 2007.

a. Findings

No findings of significance were identified.

## 1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors selected CRs related to potential operability for risk-significant components and systems. These CRs were evaluated to determine whether the operability of the components and systems was justified. The inspectors compared the operability design criteria in the appropriate sections of the TS and Updated Safety Analysis Report (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 were in place, would function as intended, and were properly controlled.

Additionally, the inspectors determined, where appropriate, compliance with bounding limitations associated with the evaluations. The inspectors reviewed the follow issues:

- Reactor Recirculation system hydraulic flow control valve fastener evaluations during the week of October 9, 2007;
- EDG building missile shield evaluations during the week of October 29, 2007;
- Control Room Emergency Recirculation system ‘B’ train unusual noise during the week of November 5, 2007;
- Motor Control Center Switchgear and Miscellaneous Electrical Equipment Areas ventilation system fan vibrations during the week of November 5, 2007;
- RCIC system following instrument line venting and controller adjustment evaluations during the week of December 3, 2007;
- ESW fuel pool cooling heat exchanger bypass valve evaluations during the week of December 10, 2007; and
- RCIC system evaluation following governor hydraulic line and flow controller repairs during the week of December 17, 2007

These reviews represented seven inspection samples.

b. Findings

No findings of significance were identified.

## 1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors selected the following post-maintenance testing activities for risk significant systems to ensure 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; and equipment was returned to its operational status following testing. The inspectors evaluated the activities against TS, the USAR, 10 CFR Part 50 requirements, licensee procedure and various NRC generic communications. In addition, the inspectors reviewed CRs associated with post-maintenance tests to determine whether the licensee was identifying problems and entering them in the corrective action program. The specific procedures and CRs reviewed are listed in the attached List of Documents Reviewed. The following post-maintenance activities were reviewed:

- Annulus Exhaust Gas Treatment System ‘A’ fan bearing repair during the week of October 9, 2007;
- Hydrogen analyzer system repairs during the week of October 1, 2007;
- Diesel Generator Building Ventilation system fan repair during the week of October 22, 2007;
- Main generator voltage regulator repair during the week of November 12, 2007
- Hot surge tank flow control valve repair during the week of November 12, 2007
- CRDM 42-31 repair during the week of December 3, 2007;
- RCIC repair during the week of December 10, 2007; and
- ESW 'B' Pump discharge strainer repair during the week of December 24, 2007.

The inspectors’ review of these post-maintenance testing activities constituted eight inspection samples.

b. Findings

1. Failure to Adequately Control Testing of the RCIC System

Introduction: The inspectors identified a Green finding of very low safety significance and a non-cited violation of 10 CFR Part 50, Appendix B, Criterion XI, “Test Control,” during an inspection of reactor core isolation cooling (RCIC) system testing between December 8 and December 9, 2007. The inspectors noted: (1) licensee personnel performed a test and later determined that the test was inappropriate; (2) personnel failed to control a test and exceeded a system design limit; and (3) personnel failed to control system configuration during testing.

Description: On December 8, 2007, the inspectors reviewed licensee test activities associated with the RCIC system. Licensee personnel had implemented a test designed to simulate a check valve pressure transient on RCIC pump start. After the performance of the test, licensee engineers reviewed the results and determined that the response was unexpected. On further review and after system vendor consultation, the licensee determined that the test procedure did not adequately incorporate requirements and acceptance criteria contained in design documents in that it placed RCIC under conditions that were not consistent with system design. The licensee determined that the inappropriate test did not affect the RCIC system adversely and continued with system testing.

The inspectors observed subsequent testing associated with the Remote Shutdown Panel (RSP). On December 8, 2007, operators were performing Work Order (WO) 200292539 to restore RCIC operability following maintenance on the flow controller. The licensee was performing tuning adjustments on the RSP RCIC flow controller in accordance with Standard Operating Instruction (SOI) E51, Section 7.17. The remote shutdown switch S11 was positioned to “Emergency” and this resulted in a bypass of the RCIC high exhaust pressure and low suction pressure trips. The test procedures and SOI-E51 did not provide information to the operators of the bypass condition, and no compensatory measures were established. During testing, the RCIC high exhaust pressure alarm was received at 25 psig, the RCIC turbine did not trip automatically and the turbine was not tripped manually by the operators. Operators responded to the conditions and reduced exhaust pressure and restored RCIC to normal operating parameters and noted that the exhaust pressure had reached 26 psig. The licensee subsequently determined that turbine exhaust pressure was maintained below design limits. However, a later evaluation determined that the RCIC pump design discharge pressure was exceeded during this event. The licensee entered this issue into their corrective action program as CR 07-31218. The inspectors determined that the procedure used to tune the RCIC system did not adequately incorporate requirements contained in design documents. Specifically, the implementation of WO 200292539 resulted in the operation of RCIC above a design limit.

On December 9, 2007, while performing surveillance instruction (SVI) E51-T2001, operators responded to indications of high RCIC pump discharge pressure and no flow by manually tripping the RCIC turbine. The licensee determined that valves associated with the flow return path to the Condensate Storage Tank were throttled to incorrect positions. The valves were throttled excessively closed due to operator error. The licensee determined that the pump minimum flow valve was open and cooling flow to the pump was maintained through the minimum flow line. The inspectors determined that the test procedures did not include adequate provisions to assure that all prerequisites for testing had been met. Specifically, performance of the test procedure resulted in an incorrect valve line-up prior to the pump run.

As part of their corrective actions, licensee personnel conducted a system equipment line-up and performed additional evaluations of the testing events to determine whether any system damage had occurred. The licensee entered the issues into their corrective action program.

Analysis: The inspectors determined that the failure to include appropriate design requirement in the test procedure for tuning the RCIC controller was a performance deficiency warranting a significance evaluation. The inspectors concluded that the finding was greater than minor in accordance with Appendix B, “Issue Screening,” of IMC 0612, “Power Reactor Inspection Reports,” dated September 20, 2007. The finding was associated with the Procedure Quality attribute of the Mitigating Systems Cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events in order to prevent undesirable consequences. Specifically, the finding resulted in the operation of RCIC system above a design limit.

The inspectors performed a significance determination of this issue using IMC 0609, “Significance Determination Process,” dated November 22, 2005, Appendix A, “Determining the Significance of Reactor Inspection Findings for At-Power Situations,” dated March 23, 2007. The finding was of very low safety significance because it did not result in an actual loss of safety function. The primary cause of this finding was related to the cross-cutting area of Human Performance per IMC 0305 H.3(a) because the licensee failed to appropriately plan the work activity by incorporating contingencies, compensatory actions, and abort criteria associated with the RCIC test configuration.

Enforcement: Criterion XI, “Test Control,” of 10 CFR 50 Appendix B, required the implementation of a test program that assures that written test procedures that incorporated requirements and acceptance limits contained in applicable design documents. Contrary to this requirement, during RCIC testing on December 8 and 9, 2007, licensee personnel failed to adequately incorporate requirements and acceptance limits into test procedures. Specifically, the performance of the procedures resulted in system operation in excess of a design limit. However, because of the very low safety significance of the issue and because the issue has been entered into the licensee's corrective action program (CR 07-31218, CR 07-31225, and CR 07-31242), the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy. (NCV 05000440/2007005-03)

2. Unresolved Item (URI) 05000440/2007005-9 Adequacy of Maintenance Associated with Emergency Service Water B Strainer Failure

On December 27, 2007, an inspection port cover, about six inches wide and nine inches tall, associated with the 'B' ESW pump discharge strainer fell off following a system test. The 'B' ESW pump was started again and water discharged into the safety-related ESW pump house. ESW 'B' was declared inoperable. The licensee determined during initial inspections that the cover fastener was potentially loose and that the cover had last been worked on during the refueling outage in April 2007. The licensee completed their initial investigation, repaired the 'B' ESW strainer, and determined that no additional equipment damage had occurred due to the water discharge into the pump house. The licensee identified that a similar event occurred in year 1990 associated with the 'A' ESW strainer. The licensee noted that some corrective actions associated with the year 1990 event were not maintained. In particular, a corrective design change was not completed and corrective periodic maintenance was not continued. The inspectors remained concerned about whether appropriate maintenance had been performed on the strainer and continued to evaluate the issue at the end of the inspection period.

1R20 Refueling and Other Outage Activities (71111.20)

a. Inspection Scope

The inspectors evaluated outage activities that began on November 28, 2007, and ended on December 10, 2007. The reactor scrammed automatically due to power supply failures associated with the digital feedwater water level control system (reference Section 4OA3.6 of this report). The inspectors reviewed activities to ensure that the licensee considered risk in developing, planning, and implementing the forced outage schedule.

The inspectors observed the reactor shutdown, outage equipment configuration and risk management, electrical lineups, selected clearances, control and monitoring of decay heat removal, control of containment activities, startup activities, and identification and resolution of problems associated with the outage.

These outage inspection activities represented a single forced outage inspection sample.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors observed surveillance testing or reviewed test data for risk-significant systems or components to assess compliance with TS, 10 CFR 50, Appendix B, and licensee procedure requirements. The testing was also evaluated for consistency with the USAR. The inspectors verified that the testing demonstrated that the systems were ready to perform their intended safety functions. The inspectors determined whether test control was properly coordinated with the control room and performed in the sequence specified in the SVI, and if test equipment was properly calibrated and installed to support the surveillance tests. The procedures reviewed are listed in the attached List of Documents Reviewed.

The inspectors selected the following surveillance testing activities for review:

- RCIC pump and valve in-service testing during the week of October 1, 2007;
- Division 3 EDG routine testing during the week of October 15, 2007;
- average power range monitor routine calibration testing conducted during the week of October 15, 2007;
- reactor coolant system routine cooldown surveillance testing for plant shutdown during the week of November 26, 2007;
- reactor coolant system leak testing for plant startup during the week of December 3, 2007; and
- Division 1 EDG routine testing on December 26, 2007

These reviews constituted one in-service; one reactor cooling system leak detection; and four routine inspection samples.

b. Findings

No findings of significance were identified.

**Cornerstone: Emergency Preparedness**

1EP2 Alert and Notification System (ANS) Evaluation (71114.02)

a. Inspection Scope

The inspectors discussed with Emergency Preparedness (EP) staff the design, operation, maintenance, and periodic testing of the ANS in the Perry Nuclear Power Plant's plume pathway Emergency Planning Zone to determine whether the ANS equipment was adequately maintained and tested in accordance with Emergency Plan commitments and procedures. The inspectors reviewed records of October 2005 through September 2007 monthly trend reports and siren test failures.

These activities completed one inspection sample.

b. Findings

No findings of significance were identified.

1EP3 Emergency Response Organization (ERO) Augmentation Testing (71114.03)

a. Inspection Scope

The inspectors reviewed and discussed with plant EP staff the emergency plan commitments and procedures that addressed the primary and alternate methods of initiating an ERO activation to augment the on-shift ERO as well as the provisions for maintaining the plant's ERO emergency telephone directory. The inspectors also reviewed reports and a sample of corrective action program records of unannounced off-hour augmentation tests, which were conducted March 2006 through September 2007, to determine the adequacy of the drills' critiques and associated corrective actions. The inspectors also reviewed the EP training records of a sample of approximately 36 Perry Nuclear Power Plant ERO personnel, who were assigned to key and support positions, to determine whether they were currently trained for their assigned ERO positions.

These activities completed one inspection sample.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors performed a screening review of Revision 27 to the Perry Nuclear Power Plant Emergency Plan, to determine whether the changes decreased the effectiveness of the licensee's emergency planning for the Perry Nuclear Power Plant. There have been no changes to the Emergency Action Levels since the last review. This review did not constitute an approval of the changes, and as such, the changes are subject to future NRC inspection to ensure that the emergency plan continues to meet NRC regulations.

These activities completed one inspection sample as defined in Inspection Procedure 71114.04-05.

b. Findings

No findings of significance were identified.

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies (71114.05)

a. Inspection Scope

The inspectors reviewed a sample of nuclear oversight staff's 2006 audit of the Perry Nuclear Power Plant EP program to verify that these independent assessments met the requirements of 10 CFR 50.54(t). The inspectors also reviewed critique reports and samples of corrective action program records associated with the 2006 biennial exercise, as well as various EP drills conducted in 2006 and 2007, in order to verify that the licensee fulfilled its drill commitments and to evaluate the licensee's efforts to identify, track, and resolve concerns identified during these activities. Additionally, the inspectors reviewed and discussed with plant EP staff the corrective action program, a sample of EP items, and corrective actions related to the facility's EP program and activities to determine whether corrective actions were acceptably completed.

These activities completed one inspection sample.

b. Findings

No findings of significance were identified.

1EP7 Drill Evaluation (71114.07)

a. Inspection Scope

The inspectors observed licensee performance during one site EP drill. This drill was in conjunction with a Force-on-Force inspection documented in IR 05000440/2007403. The inspectors observed communications, event classification, and event notification activities in the simulator by the shift manager. The inspectors also observed portions of the post-drill critique to determine whether their observations were also identified by the licensee's evaluators. The inspectors verified that minor issues identified during this inspection were entered into the licensee's corrective action program.

These activities represent one inspection sample.

b. Findings

No findings of significance were identified.

## 2. RADIATION SAFETY

**Cornerstone: Occupational Radiation Safety**

2OS1 Access Control to Radiologically Significant Areas (71121.01)

.1 Plant Walkdowns and Radiation Work Permit Reviews

a. Inspection Scope

The inspectors reviewed the licensee's procedures and its methods for the assessment of internal dose as required by 10 CFR 20.1204 to determine if methodologies were technically accurate and would include the impact of hard to detect radionuclides such as pure beta or alpha emitters, if applicable. No worker intakes that resulted in a committed effective dose equivalent in excess of 50 millirem occurred during the period reviewed by the inspectors (January 2006 - September 2007).

The inspectors reviewed the licensee's physical and administrative controls for the storage of highly activated and/or contaminated materials (non-fuel) within the spent fuel pool. In particular, the radiological controls for non-fuel materials stored in these pools were evaluated to ensure that adequate barriers were in place to reduce the potential for the inadvertent movement of these materials and to assess compliance with the licensee's procedures and for consistency with NRC regulatory guidance.

These reviews represented two required inspection samples.

b. Findings

No findings of significance were identified.

.2 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed the licensee's self-assessments, audits, Licensee Event Reports (LERs), and Special Reports related to the access control program to verify that identified problems associated with access control to radiologically significant areas were entered into the corrective action program for resolution.

Additionally, the inspectors reviewed the licensee's documentation for all potential Performance Indicator (PI) events occurring since the NRC's last review of these areas in 2006 to determine if any of these events involved dose rates greater than 25 Rem/hour at 30 centimeters or greater than 500 Rem/hour at one meter or involved unintended exposures greater than 100 millirem total effective dose equivalent (or greater than 5 Rem shallow dose equivalent or greater than 1.5 Rem lens dose equivalent). One event was identified that is discussed in section 4OA1 of this report.

These reviews represented one required inspection sample.

b. Findings

No findings of significance were identified.

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

.1 Inspection Planning

a. Inspection Scope

The inspectors obtained a list of the licensee's on-line and outage work activities ranked by estimated exposure that were completed during the 2007 refueling outage and reviewed the following eight radiologically significant work activities which were likely to result in the highest personnel collective exposures:

- scaffolding activities;
- operations activities;
- ALARA support activities;
- chemical decontamination projects;
- instrument and control activities;
- plant maintenance activities;
- valve repairs; and
- snubber activities in the drywell.

Procedures associated with maintaining occupational exposures ALARA and processes used to estimate and track work activity specific exposures were also reviewed.

These reviews supplement inspection activities previously documented in IR 05000440/2007003.

b. Findings

No findings of significance were identified.

.2 Radiological Work Planning.

a. Inspection Scope

The inspectors evaluated the licensee’s list of work activities, ranked by estimated/actual exposure, that were completed during the 2007 refueling outage and selected the eight work activities of highest exposure significance.

The inspectors compared the results achieved (dose rate reductions, person-rem used) with the intended dose established in the licensee’s ALARA planning for these work activities. The inspectors determined the reasons for inconsistencies between the intended and actual work activity doses.

The inspectors reviewed the integration of ALARA requirements into work procedure and radiation work permit (RWP) documents and also compared the person-hour estimates provided by maintenance planning and other groups to the radiation protection group with the actual work activity time requirements and evaluated the accuracy of these time estimates.

The inspectors also evaluated the radiation protection group generated shielding requests with respect to dose rate reduction and assessed the post-job work activity reviews to ensure that identified problems were entered into the licensee’s corrective action program.

These reviews represented one required and three optional inspection samples, and supplemental inspection activities previously documented in IR 05000440/2007003.

b. Findings

No findings of significance were identified.

.3 Verification of Dose Estimates and Exposure Tracking Systems

a. Inspection Scope

The inspectors reviewed the licensee’s method for adjusting exposure estimates and re-planning work, when unexpected changes in scope or emergent work are encountered to ensure that adjustments to estimated exposure (intended dose) are based on sound radiation protection and ALARA principles. The inspectors reviewed adjustments to the intended dose and compared the revised dose estimated to the original ALARA planning process.

This review represented one required inspection sample.

b. Findings

Introduction: One inspector-identified Green finding of very low safety significance, and an associated NCV of NRC requirements, were identified for the failure to adequately implement effective radiological dose controls during Refuel Outage 11 associated with plant scaffolding activities. Work control and planning issues including building and removing unnecessary scaffolds for work activities that had been removed from the outage scope contributed to unnecessary worker doses.

Description: The initial dose estimates for plant scaffold activities were primarily based on historical dose rates for the same or similar work activity and person-hour estimates provided by the work groups responsible for the evolution. The initial dose estimate for this RWP series (07-6225 and 07-6335) was 15.959 person-rem and assumed a nominal 65 percent of the dose would be received in the drywell while the remaining 35 percent of the dose was expected to be from the balance of the plant. The initial dose estimate had been adjusted for the expected dose reduction that the chemical decontamination of the reactor recirculation system would have had on drywell dose rates. Due to unforeseen circumstances (unisolable system in-leakage), the chemical decontamination of the reactor recirculation system could not be completed this outage as scheduled. Consequently, the dose estimates for drywell RWPs, including the scaffolding RWPs, were readjusted to account for changes in drywell work area dose rates. Additionally, the station experienced an increase in drywell dose rates attributable to a plant shut down crud burst. Therefore, RWPs impacted by these conditions also needed to be adjusted for changes in dose rates.

Due to these circumstances, the licensee revised the scaffold dose estimate from 15.959 person-rem to 64.184 person-rem. Once the outage dose estimates were revised, the station concluded that the projected accumulated doses were unacceptable and held station ALARA and outage scope reduction meetings to reduce the outage scope, thereby reducing the overall outage dose. As a result, outage work scope was reduced; however, the licensee did not re-evaluate the scaffolding dose estimate, which remained at 64.184 person-rem. The licensee and the inspector agreed that the 64.184 person-rem estimate should have been reduced to 26.337 person-rem because of the reduction in outage scope. The actual dose expenditure of 46.686 person-rem exceeded this estimate, i.e., 26.337 person-rem, by 178 percent.

As documented in the station's post-outage report, scaffolds were built in the field in support of WOs that had been deleted from the outage. The primary cause being that the station entered the outage with insufficient detailed planning. Additionally, the station did not plan for contingencies, compensatory actions, nor clearly define abort criteria, should the station be unable to complete chemical decontamination of the reactor recirculation system as scheduled. Also, during the outage the station attempted to establish radiological controls for field activities in parallel with planning the work and scope control. These activities hampered the licensee's ALARA planning, as work crews commenced field activities and erected unnecessary scaffolds.

Specific examples of radiological planning issues included a snubber WO that called for one scaffold while the actual work required 143 scaffolds or ladders and a flow accelerated corrosion inspection WOs that listed a need for 35 scaffolds, but did not provide any direction as to what order or priority the scaffolds were to be built.

Analysis: The failure to adequately implement radiological dose controls represents a performance deficiency as defined in NRC IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening." The issue was associated with the Program and Process attribute of the Occupational Radiation Safety Cornerstone and affected the cornerstone objective to ensure the adequate protection of the worker health and safety from exposure to radiation from radioactive material during routine civilian nuclear reactor operation. Therefore, the issue was more than minor and represented a finding which was evaluated using the SDP.

This finding involved radiological controls and ALARA planning, and the inspectors used IMC 0609, Appendix C, "Occupational Radiation Safety SDP," to assess its significance. The inspectors concluded that the finding did not result in an occupational overexposure, a substantial potential for an overexposure, or a compromised ability to assess dose. The inspectors determined that the finding involved ALARA planning and work controls because the actual dose for scaffolding activities exceeded 5 person-rem and exceeded the licensee's dose estimate, which was determined to be ALARA for this work activity, by greater than 50 percent. Since the licensee's current three-year rolling collective dose average is less than 240 person-rem per unit, the inspectors concluded that the SDP assessment for this finding was of very low safety significance (Green). A cross-cutting aspect in the area of human performance in work control for appropriately planning work activities (H.3.a) was associated with this finding.

Enforcement: Perry Nuclear Power Plant Technical Specification 5.4.1.a. requires the licensee to establish, implement, and maintain procedures recommended by Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Regulatory Guide 1.33, Section D.7.e, requires procedures for access control to radiation areas including a radiation work permit system and procedures for implementation of an ALARA program, which are provided by the licensee, in part, through Station Procedure NOP-WM-7003 "Radiation Work Permit," Revision 03. Specifically, procedure step 4.2.7 requires that the total dose estimate be determined for work tasks. Contrary to the above, the licensee failed to adequately determine a total dose estimate for work tasks following reductions in work scopes which affected those tasks. This resulted in the licensee failing to establish controls to maintain dose to workers ALARA. However, because the issue was of very low safety significance, was entered into the licensee's corrective action program (AR 0717995 and 0729213), and included corrective actions for the assignment of high impact teams to address and evaluate lessons learned from the refuel outage, the NRC is treating the issue as an Non-Cited Violation (NCV), in accordance with Section VI.A.1 of the NRC's Enforcement Policy (NCV 05000440/2007005-04).

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

### .1 Inspection Planning

#### a. Inspection Scope

The inspectors reviewed the current revision to the licensee's Offsite Dose Calculation Manual (ODCM) and the licensee's Annual Radioactive Effluent Release Reports for calendar years 2005 and 2006, along with selected radioactive effluent release data for year-to-date 2007. The inspectors reviewed anomalous results reported in those radioactive effluent release reports that were entered into the licensee's corrective action program and resolved. The inspectors determined whether evaluations were completed by the licensee to assess the potential radiological impact of any modifications made to the ODCM since the previous NRC inspection of the effluent control program. Similarly, the inspectors determined if the ODCM modifications necessitated changes to the effluent radiation monitor alarm setpoints, and if those changes were made, as warranted. The inspectors also reviewed, as applicable, audits, self-assessments and LERs that involved unanticipated offsite releases of radioactive effluents. The effluent reports, effluent data, and licensee evaluations were reviewed to determine whether the radioactive effluent control program was implemented as required by the radiological effluent technical specifications (RETS) and the ODCM, to determine if public dose limits resulting from effluents were met, and to determine if any anomalies in effluent release data were adequately understood by the licensee and were assessed and reported.

The inspectors evaluated the licensee's analyses of any effluent pathways resulting from spills, leaks or abnormal/unmonitored liquid and gaseous effluent discharges over the previous several years. The inspectors also determined whether the licensee had identified those systems and the associated equipment that were potentially vulnerable to leaks of contaminated fluids and whether the licensee had developed adequate mechanisms to identify spills/leaks should they occur. Moreover, the inspectors reviewed the licensee's recently developed plan for assessing the condition of buried piping and systems which carry radioactive fluids.

The inspectors reviewed the ODCM to identify the gaseous and liquid effluent radiation monitoring systems and associated effluent flow paths including in-line flow measurement devices and reviewed the description of radioactive waste systems and effluent pathways provided in the Updated Final Safety Analysis Report (UFSAR) in preparation for the onsite inspection.

The inspectors reviewed the licensee's RETS/ODCM and the licensee's procedures and surveillance activities to determine whether a program was in place for identifying potential spills/leaks and for their assessment.

These reviews represented one inspection sample.

#### b. Findings

No findings of significance were identified.

.2 <u>Walkdown of Effluent Control Systems, Review of System/Program Modifications, and Instrument Calibrations and Quality Control</u>

a. <u>Inspection Scope</u>

The inspectors walked down the point of discharge liquid and gaseous effluent radiation monitors, particulate/charcoal samplers and the associated flow indicating devices to observe current system configuration with respect to the descriptions in the UFSAR and to determine if isokinetic sampling conditions existed.

The inspectors reviewed the technical justification for changes made by the licensee to the ODCM, as well as changes to the liquid or gaseous radioactive waste system design or operation since the last NRC inspection, to determine whether these changes affected the licensee's ability to maintain effluents as low as reasonably achievable and whether changes made to monitoring instrumentation resulted in non-representative monitoring of effluents. Annual radioactive effluent release reports for the two years preceding the inspection were evaluated for any significant changes (factor of five) in either the quantities or kinds of radioactive effluents and for any significant changes in offsite dose which could be indicative of problems with the effluent control program.

The inspectors reviewed records of the most recent instrument calibrations (channel calibrations) for each point-of-discharge effluent radiation monitor and for selected effluent flow measurement devices to determine if these monitors had been calibrated consistent with industry standards and in accordance with station procedures, TS and the ODCM. Specifically, the inspectors reviewed calibration records for the following effluent radiation monitors and selected flow measuring devices:

- Unit 1 Vent Effluent Monitor;
- Unit 2 Vent Effluent Monitor;
- Off-Gas Vent Effluent Monitors;
- Turbine Building / Heater Bay Effluent Monitor;
- Liquid Radwaste Effluent Monitor; and
- ESW Effluent Monitors.

The inspectors reviewed effluent radiation monitor setpoint bases and alarm values for the point of discharge gaseous effluent radiation monitors to assess their technical adequacy and for compliance with ODCM criteria. The inspectors selectively reviewed gaseous and liquid effluent monitor operational trend data and discussed equipment performance with the chemistry staff. The trend data was reviewed and discussions were held to determine if the licensee had identified potential effluent monitoring system material condition issues and had taken actions or developed plans to address identified deficiencies.

The inspectors reviewed chemistry department quality control data for those instrumentation systems used to quantify effluent releases for indications of potential degraded instrument performance. Specifically, the inspectors reviewed the most recent efficiency calibration records and lower limit of detection (LLD) determinations and selected other quality control data for chemistry department gamma spectroscopy systems.

These reviews represented three inspection samples.

b. Findings

No findings of significance were identified.

.3 Effluent Release Packages, Abnormal/Unmonitored Releases, and Dose Calculations

a. Inspection Scope

The inspectors reviewed selected batch liquid effluent release packages and gaseous effluent sampling data for periods in 2006 and 2007, including results of chemistry sample analyses, the application of vendor laboratory analysis results for difficult to detect nuclides, and the licensee's effluent release procedures and practices. Also, the inspectors reviewed the methods for calculating the projected doses to members of the public from these releases. These reviews were performed to determine if the licensee adequately applied analysis results in its dose calculations consistent with the methodologies in its ODCM and to determine if appropriate treatment equipment was used and effluents were released in accordance with the RETS/ODCM to meet procedural requirements.

The inspectors also reviewed the licensee's practices for compensatory sampling during periods of effluent monitor inoperability including extended periods when radiation monitors were out-of-service to determine if compliance with ODCM action statements was achieved.

The inspectors selectively reviewed monthly and quarterly dose calculations and projections to ensure that the licensee properly calculated the offsite dose from radiological effluent releases and to determine if any RETS/ODCM (i.e., Appendix I to 10 CFR Part 50) design objectives (limits) were exceeded. The inspectors reviewed the Perry source term data to determine if all applicable radionuclides that were released in effluents were included in the dose calculations, as applicable.

The inspectors reviewed the licensee's 10 CFR 50.75(g) files which documented historical and more recent spills/leaks of contaminated liquids associated with its operating units that dated back to the site's early operating period. The inspectors selectively reviewed the site's historical spills/leaks with the potential for a radiological impact. The inspectors reviewed the licensee's evaluation of those incidents to assess the adequacy of the licensee's evaluations including the associated projected dose to the public, as applicable. The inspectors reviewed the 2007 study of the hydrogeologic characteristics of the site including the groundwater flow patterns. Additionally, the inspectors reviewed the licensee's recently expanded groundwater monitoring program for detecting potential leaks and spills. These reviews were performed to determine if the licensee had a program for early detection of spills/leaks, understood the site's groundwater flow characteristics and pathways to the environment, and to determine if the licensee had the capability to assess the radiological impact of a future spill/leak should it occur.

The inspectors reviewed the results of the radiochemistry inter-laboratory cross-check comparisons to validate the licensee's analyses capabilities. The inspectors reviewed the licensee's evaluation of disparate inter-laboratory comparisons and the associated corrective actions for any deficiencies identified, as applicable. In addition, the inspectors reviewed inter-laboratory comparison data for the licensee's vendor laboratory to assess the analytical capabilities of the vendor laboratory for those difficult-to-detect nuclides specified in the ODCM.

These reviews represented five inspection samples.

b. Findings

No findings of significance were identified.

.4 Ventilation Filter Testing

a. Inspection Scope

The inspectors reviewed the most recent results for both divisions of the main control room and the auxiliary building emergency ventilation system filter testing to determine whether the test methods, frequency, and test results met TS requirements, as provided in The American Society of Mechanical Engineers (ASME) Standard N510-1980, "Testing of Nuclear Air Treatment Systems." Specifically, the inspectors reviewed the results of in-place high efficiency particulate air and charcoal absorber penetration/leak tests, laboratory tests of charcoal absorber methyl iodide penetration and in-place tests of pressure differential across the combined high efficiency particulate air filters/charcoal absorbers.

These reviews represented one inspection sample.

b. Findings

No findings of significance were identified.

.5 Identification and Resolution of Problems

a. Inspection Scope

The inspectors reviewed selected Chemistry Department self-assessment, Nuclear Oversight Department audits, and CRs generated in 2006 and 2007, which focused on chemistry and the radioactive effluent treatment and monitoring program. The review was performed to determine if identified problems were entered into the corrective action program for resolution. The inspectors also determined if the licensee's problem identification and resolution program, together with its audit and self-assessment activities, were capable of identifying repetitive deficiencies or significant individual deficiencies in problem identification and resolution.

The inspectors reviewed various CRs related to the radioactive effluent treatment and monitoring program, interviewed staff, and reviewed associated licensee evaluations and corrective action documents to determine if the following activities were being conducted in an effective and timely manner commensurate with their importance to safety and risk:

- initial problem identification, characterization, and tracking;
- disposition of operability/reportability issues;
- evaluation of safety significance/risk and priority for resolution;

- identification of repetitive problems;
- identification of contributing causes;
- identification and implementation of effective corrective actions;
- resolution of NCVs tracked in the corrective action system; and
- implementation/consideration of risk-significant operational experience feedback.

These reviews represented one inspection sample.

b. Findings

No findings of significance were identified.

4OA1 Performance Indicator Verification (71151)

**Cornerstone: Mitigating Systems**

a. Inspection Scope

The inspectors reviewed LERs, licensee data reported to the NRC, plant logs, and NRC inspection reports to verify the following PIs for the time periods indicated:

- Safety System Functional Failures for the period from the 2nd Quarter of 2006 through the 2nd Quarter 2007 for a total of five quarters;
- ESW cooling water systems for the period from the 3rd Quarter of 2006 though the 2nd Quarter of 2007 for a total of four quarters
- RHR system for the period beginning in the 3rd Quarter of 2006 though the 2nd Quarter of 2007 for a total of four quarters;
- High Pressure Core Spray injection system for the period beginning in the 3rd Quarter of 2006 though the 2nd Quarter of 2007 for a total of four quarters; and
- RCIC heat removal system for the period beginning in the 3rd Quarter of 2006 though the 2nd Quarter of 2007 for a total of four quarters.

The inspectors verified that the licensee accurately reported performance as defined by the applicable revision of Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator guideline."

These reviews represented five inspection samples.

b. Findings

No findings of significance were identified; however, the inspectors have questioned the characterization of two scram events and one power change event that occurred in June 2007. At the end of the inspection period, these issues were under evaluation in accordance with the NRC's Frequently-Asked-Questions process.

**Cornerstone: Emergency Preparedness**

a. Inspection Scope

The inspectors reviewed the licensee’s records associated with the three EP PIs listed below. The inspectors verified that the licensee accurately reported these indicators in

accordance with relevant procedures and Nuclear Energy Institute guidance endorsed by NRC. Specifically, the inspectors reviewed licensee records associated with PI data reported to the NRC for the period October 2006 through June 2007. Reviewed records included: procedural guidance on assessing opportunities for the three PIs; assessments of PI opportunities during pre-designated Control Room Simulator training sessions, the 2006 biennial exercise, and other drills; revisions of the roster of personnel assigned to key ERO positions; and results of periodic ANS operability tests.
The following PIs were reviewed:

- ANS;
- ERO drill participation; and
- drill and exercise performance.

These activities completed three inspection samples.

b. Findings

No findings of significance were identified.

**Cornerstone: Occupational Radiation Safety**

.1 Radiation Safety Strategic Area

a. Inspection Scope

The Inspectors reviewed the licensee's PI submittals for the periods listed below. The inspectors used PI definitions and guidance contained in Revision 4 of Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline," to verify the accuracy of the PI data. The following PI was reviewed:

- Occupational Exposure Control Effectiveness:

The inspectors reviewed the licensee's assessment of the PI for occupational radiation safety to determine if indicator related data was adequately assessed and reported during the previous four quarters. The inspectors compared the licensee's PI data with the CR database, reviewed radiological restricted area exit electronic dosimetry transaction records and discussed data collection and analysis methods for PIs with licensee representatives.

This review represented one required inspection sample.

b. Findings

No findings of significance were identified.

.2 Radiation Safety Public Performance Indicator Verification

a. Inspection Scope

The inspectors reviewed, at a minimum, the most recent 12 months of LERs, licensee data reported to the NRC, selected plant logs, and NRC inspection reports to verify the following PIs reported by the licensee for the third Quarter of 2007:

- RETS/ODCM radiological effluent occurrence.

The inspectors verified that the licensee accurately reported performance as defined by the applicable revision of Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline."

These PI reviews constituted one inspection sample.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

**Cornerstone: Initiating Events, Mitigating Systems, Barrier Integrity, and Emergency Preparedness**

**Routine Review of Identification and Resolution of Problems**

a. Inspection Scope

As discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to determine whether they were being entered into the licensee's corrective action program at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed.

This is not an inspection sample

b. Findings

No findings of significance were identified.

.2 In-Process Observation of Corrective Actions Associated with the NRC's August 15, 2007 Confirmatory Order.

a. Inspection Scope

By letter dated August 15, 2007, the NRC issued an immediately effective Confirmatory Order EA-07-199 (Order) that formalized commitments made by the FirstEnergy Nuclear Operating Company (FENOC). Commitments made by FENOC were documented in its July 16, 2007, letter responding to the NRC's May 14, 2007, Demand for Information (DFI).

The DFI was issued in response to information provided by FENOC relative to an analysis performed by Exponent Failure Analysis Associates and Altran Solutions Corporation into the 2002 Davis-Besse reactor pressure vessel head degradation event. On June 13, 2007, FENOC provided its response to the DFI and on June 27, 2007, the NRC held a public meeting with FENOC to discuss the DFI response. On July 16, 2007, FENOC provided a supplemental response to the DFI that provided additional detail regarding the planned implementation of commitments established in the June response to the DFI.

In addition to implementing interim corrective actions, the Order required the licensee to:

1. Conduct regulatory sensitivity training for selected FENOC and non-FENOC FirstEnergy employees to ensure those employees identified and communicated information that has the potential for regulatory impact either at FENOC sites or within the nuclear industry to the NRC. The licensee was to provide the population to be trained, the training methodology and materials, and the training objective at least 30 days prior to conducting the training. All training was to be conducted by November 30, 2007;
2. Conduct effectiveness review to determine if an appropriate level of regulatory sensitivity was evident among FirstEnergy employees including those who received regulatory sensitivity training in January 2008 and 2009;
3. Develop a formal process to review technical reports prepared as part of a commercial matter. The process was to be implemented no later than December 14, 2007;
4. Assess its Regulatory Communications Policy and make process changes to its NRC correspondence procedure to ensure specific questions are asked during the process relative to the experience gained from efforts to respond to the NRC's May 14, 2007, DFI. Revisions were to be completed by December 14, 2007;
5. Provide an Operating Experience document to the nuclear industry by September 15, 2007; and
6. Complete a root cause evaluation of the events that culminated in the issuance of the May 14, 2007, DFI and provide the NRC with a summary of the analysis no later than December 14, 2007.

To assess the licensee's activities associated with item 1, i.e., conduct regulatory sensitivity training, the inspectors reviewed the licensee's training material; class hand-outs; qualifications of the individual providing the training; training objectives: and the basis for the individuals selected to receive the training. In addition, the inspectors observed the training provided to FirstEnergy and FENOC individuals during the week of October 22, 2007, at the Perry power plant.

This review represents one in-depth inspection sample.

b. Issues

No findings of significance were identified. Additional information associated with this review is documented in Davis Besse IR 05000346/2007005 and Beaver Valley IRs 05000334/2007005 and 05000412/2007005.

.3 EDG Headbolts/Filters/Relays

a. Inspection scope

On November 26, 2007, after a Division 1 EDG maintenance outage, the inspectors reviewed several material issues that were discovered during the outage.

The first issue was the discovery that four hydraulic lifters were found damaged. The licensee determined that the broken lifters did not affect operability of the EDG since the lifters' function was to improve the long term performance of the cam shafts. The specific damage to the four hydraulic lifters was a vertical shear, but the lifters remained in place and did not become foreign material in the diesel engine. The licensee determined that industry experience with failed hydraulic lifters demonstrated the EDGs would remain operable for 4000 to 8000 run hours, within the EDG's mission time requirements. The licensee replaced all Division 1 EDG hydraulic lifters.

The inspectors also reviewed issues associated with an Agastat timing relay failure, fuel oil ultra low sulfur deliveries, starting air system, and jacket water system performance.

During the Division 1 EDG maintenance outage, a cylinder head bolt as-found condition torque was 2818 ft-lbs. The minimum required torque value was 3420 to 3780 ft-lbs. This issue was entered into the licensee corrective action program as CR 07-30279. The licensee determined that the EDG remained operable because the entire torque value of the cylinder head was above the minimum required. During the November 2006 Division 2 EDG maintenance outage, several cylinder head bolts were identified as below minimum torque value. The licensee determined in their investigation (CR 06-9890) that the EDG was operable and the cause of the nonconforming degraded condition was an as-built issue and improper maintenance practices. The licensee determined that, when the diesel generators were installed, the methods of applying torque to the cylinder head fasteners were not accurate. During the November 2006 investigation it was determined that three cylinder heads on Division 1 and six cylinder heads on Division 2 had not been evaluated for torque values since 1994.

This review represented one in-depth inspection sample.

b. Findings

Introduction: The inspectors identified a Green finding of very low safety significance and a non-cited violation of 10 CFR 50 Appendix B, Criterion XVI, “Corrective Action,” when a nonconforming condition associated with the Division 1 Emergency Diesel Generator was discovered on November 16, 2007. One cylinder head stud was torqued below the minimum required torque setting. The inspectors determined that the licensee failed to perform an appropriate extent-of-condition review when several cylinder head studs were found below minimum torque level on November 13, 2006.

Description: On November 13, 2006, licensee personnel identified during a Division 2 EDG maintenance period that head stud nuts on four cylinder heads were below required minimum torque value. The UFSAR stated that the diesel generator was to be capable of operating at rated speed and no load for seven days without degradation of engine performance or reliability. At the time of discovery, the licensee entered this operable, but nonconforming condition into their corrective action program as

CR 06-9890. An operability evaluation was performed to document that the EDGs were operable but nonconforming. The minimum cylinder head stud torque specified was required to avoid loss of preload that may result in combustion chamber leakage and head stud fatigue failures.

The licensee identified that the cause of the issue was due to an inadequate technique for installation of the cylinder valve head studs that existed before 1994. Since 1994 all cylinder head valve studs had been verified except three heads on Division 1 and six heads on Division 2. Due to the time constraints in determining a cylinder valve head stud torque value, the licensee scheduled these checks for the next divisional EDG outage; the Division 1 outage to be performed in November 2007 and the Division 2 outage in November 2008.

During the refueling outage in April 2007, the engineering and maintenance groups performed work on both the Division 1 and 2 EDGs. In both work windows the licensee did not verify any of the unknown cylinder valve head stud torque values. During the subsequent Division 1 EDG outage in November 2007, a cylinder valve head stud torque was found to be 2818 ft-lbs, when the required minimum was 3420 ft-lbs. All other unknown head studs on Division 1 were found with nominal torque values.

The licensee entered the issue into their corrective program and planned an extent of condition review for the Division 2 EDG during the next scheduled outage in November 2008.

Analysis: The inspectors determined that the failure to take prompt corrective action was a performance deficiency warranting further evaluation. The inspectors reviewed the finding using the guidance contained in Appendix B, "Issue Disposition Screening," of IMC 0612, "Power Reactor Inspection Reports," dated September 20, 2007. The finding was more than minor because it was associated with the Equipment Performance attribute of the reactor safety Mitigating Systems Cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The primary cause of this finding was related to the cross-cutting area of Problem Identification and Resolution per IMC 0305 P.1(d) because the licensee failed to take appropriate corrective action to address safety issues in a timely manner. The licensee failed to perform an extent-of-condition analysis during the refueling outage when a nonconforming condition actually existed.

The inspectors reviewed this finding in accordance with IMC 0609 Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations." This issue screened as having very low safety significance (Green) because the finding was a design deficiency confirmed not to result in a loss of operability per the Part 9900 Technical Guidance for operability determination process for operability and functional assessment.

Enforcement: Criterion XVI, "Corrective Action," of 10 CFR 50, Appendix B, states that measures shall be established to assure that conditions adverse to quality, such as deficiencies and nonconformances are promptly corrected. Contrary to this requirement, the licensee failed to perform an extent-of-condition review for a non-conformance that was identified in November of 2006 at the first available opportunity during Refueling Outage 11 in the second quarter of 2007. Because this violation was of very low safety significance and was entered into the licensee's corrective action program, this violation is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 05000440/2007005-05).

.4 Fuel Channel Drop

a. Inspection scope

The inspectors selected a root cause evaluation associated with a dropped fuel channel event that occurred on October 18, 2007. The report was reviewed to ensure that the full extent of the issue was identified, an appropriate evaluation was performed, and appropriate corrective actions were specified and prioritized. The inspectors evaluated the report against the requirements of the licensee's corrective action program and 10 CFR 50, Appendix B.

b. Findings

Introduction: On October 18, 2007, a Green finding of very low safety significance was self-revealed when a fuel channel dislodged from a grapple during movement in the spent fuel pool. The licensee implemented a design change to the spent fuel handling bridge grapple system that resulted in an inadequate method of verification for grapple attachment to the fuel channel.

Description: The licensee implemented a design change to install a new air-operated grapple system for a safety-related refueling bridge that serviced the spent fuel pool. The new grapple design, termed "In Storage Rack Channel Grapple" (ISRCG), was implemented during a refueling outage that began in April 2007 and was used for subsequent channel movements.

On October 18, 2007, licensee personnel were conducting movements of fuel channels in the spent fuel pool as part of a spent fuel pool cleanup project. During one of these movements, the fuel channel became dislodged from the ISRCG and dropped down in the pool. The channel impacted the spent fuel pool fuel racks at the bottom of the pool and then toppled over onto several spent fuel assemblies.

The new air-operated ISRCG design consisted of a grapple block with a lower block portion shaped to fit down inside a fuel channel. Once the lower portion of the grapple block was sufficiently lowered into the fuel channel, air-operated fingers could be extended under the fuel channel tabs to engage the channel for lifting. This new design replaced a simple "J-hook" style design and method.

The licensee investigated the cause of the failure and conducted testing of the failed ISRCG. The licensee was able to reproduce the failure by not fully inserting the grapple block prior to engaging the fingers. This resulted in a condition where the finger on one side extended out but was stopped by the side of the channel tab instead of extending fully underneath the tab. The licensee determined that, due to its physical design, ISRCG engagement could not be visually verified when operating the grapple. Following additional review, the licensee determined that the root cause of the event was an inadequate method for verification of engagement of the ISRCG to the fuel channel.

Because the new ISRCG design was determined to have resulted in a dropped channel onto spent fuel due to an inadequate method of verification for grapple attachment, the inspectors determined that the licensee failed to implement an adequate suitability review for application of the new ISRCG design to operations associated with the spent fuel pool

As part of their immediate corrective actions, the licensee reinstated the previous "J-hook" design and method that provided for adequate verification of grapple attachment and entered the issue into their corrective action program.

Analysis: The inspectors determined that the failure of the licensee to adequately review the suitability of the ISRCG design and processes for operations associated with the spent fuel pool was a performance deficiency warranting a significance evaluation. The inspectors concluded that the finding was greater than minor in accordance with Appendix B, "Issue Screening," of IMC 0612, "Power Reactor Inspection Reports," dated September 20, 2007. The finding was associated with the design control attribute of the reactor safety Barrier Integrity Cornerstone and affected the cornerstone objective of providing reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. Specifically, the finding resulted in an event that challenged spent fuel cladding.

The primary cause of this finding was related to the cross-cutting area of Human Performance per IMC 0305 H.2(d) because the organization failed to ensure that equipment, including physical improvements, was adequate to assure nuclear safety. The new ISRCG design was considered by the licensee to be an improvement over the "J-hook" design to provide a more efficient method for fuel channel movement. However, the ISRCG did not allow for adequate verification of grapple attachment and resulted in a dropped channel and a challenge to spent fuel integrity.

Although not suitable for SDP review, regional management determined that the finding was of very low safety significance because the dropped fuel channel was determined to have not caused damage to the spent fuel.

Enforcement: Enforcement action does not apply because the performance deficiency did not involve a violation of a regulatory requirement. (FIN 05000440/2007005-06)

4OA3 Event Follow-Up (71153)

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

.1 (Closed) LER 05000440/2007-002-00: Shutdown Cooling Pump Trip Results in Operation Prohibited by Technical Specifications

Introduction: A finding of very low safety significance and an associated non-cited violation of 10 CFR 50, Appendix B, Criterion XVI was self-revealed on July 11, 2007, when the licensee was unable to meet TS requirements to verify the availability of an alternate decay heat removal system when a residual heat removal shutdown cooling subsystem was inoperable.

Description: On July 11, 2007, the ‘B’ RHR pump, that was providing shutdown cooling for the reactor, tripped off. An instrument and control technician was performing a RCIC surveillance test and, contrary to procedures, loosened a wire connection from an electrical terminal. This caused the RHR ‘B’ pump to trip on July 11, 2007, at 11:13 pm. With the unit in Mode 4, TS 3.4.10 required two RHR shutdown cooling subsystems to be operable. Action A.1, of TS 3.4.10, required the licensee to verify an alternate method of decay heat removal within one hour for each inoperable RHR shutdown cooling subsystem. With only the RHR 'A' subsystem operable, the licensee could not satisfy this condition of TS 3.4.10. Some systems were identified by the licensee to have some decay heat removal capacity, but none were of enough capacity to be considered an alternate decay heat removal system.

The licensee verified that no common cause failure existed and placed the RHR ‘A’ subsystem in shutdown cooling mode on July 12, 2007, at 1:10 a.m. With initial troubleshooting completed, the RHR ‘B subsystem was declared operable on July 12, 2007, at 5:59 am. This represented over 5 hours where TS 3.4.10, A.1 completion time was not met.

On May 23, 2004, the licensee failed to meet TS 3.4.10, A.1, requirements and this was documented as NCV 05000440/2005002-12. The licensee planned to complete installation of an alternate decay heat removal system during the April 2007 refueling outage, but the activity was removed from the outage schedule for scope consideration and work coordination issues. The licensee had yet to install an alternate decay heat removal system plans as of the end of the inspection period. The licensee entered the issue into their corrective action program.

Analysis: The inspectors determined that this finding was more than minor because it was related to the Equipment Performance attribute of the Mitigating System Cornerstone and affected the cornerstone objective to ensure the availability of a mitigating system that responds to initiating events to prevent undesirable consequences. Specifically, the finding affected the availability of a decay heat removal system.

Although not suited for Significance Determination Process review, the finding was determined through management review to be of very low safety significance because the licensee restored shutdown cooling within 2 hours and the plant remained in Mode 4. The primary cause of this finding was related to the cross-cutting area of Human Performance per IMC 0305 H.2(a), because the licensee failed to minimize long-standing equipment issues and maintenance deferral. Specifically, the licensee failed to complete the alternate decay heat removal system installation prior to the July 11, 2007, event.

Enforcement: 10 CFR 50, Appendix B, Criterion XVI required the licensee to assure deficiencies adverse to quality were corrected in a timely manner. Contrary to this requirement, the licensee failed to correct the deficiency of a lack of an alternate decay heat removal system in a timely manner despite reasonable opportunity to do so since May 2004. Because of the very low safety significance and because the issue has been entered into the licensee’s corrective action program, the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy. This LER is closed. (NCV 05000440/2007005-07)

.2 (Closed) LER 05000440/2007-003-00: Improper Containment Floor Grating Installation Results In Unanalyzed Condition

On August 26, 2007, the licensee identified that a 3' x 7' section of floor grating located in the reactor containment building was missing required hold down fasteners. Licensee personnel conducted an engineering evaluation on August 27, 2007, and determined that an unanalyzed condition existed. The licensee determined that this grating could become dislodged during a postulated loss-of-coolant accident. The grating then could impact the emergency core cooling system (ECCS) suction strainer associated with the HPCS, RHR ‘A’, and RHR ‘B’ pump suctions. The licensee declared HPCS system as well as the ‘A’ and ‘B’ RHR trains inoperable pending issue resolution. The licensee entered TS 3.5.1 ECCS action statements for the three systems. The grating was restored to design configuration and the TS LCO 3.5.1 was exited on the same day. The licensee determined that the grating had been removed during a July 2007 plant outage to support a reactor recirculation pump motor replacement. The licensee identified that the significant regulatory issue associated with the event was that the subsequent mode changes after July 23, 2007, were prohibited. The licensee determined that the cause of the event was inadequate detail in the WO, inadequate turnover of the work, and inadequate training for configuration control. Corrective actions included restoration of the grating to design configuration, procedure revisions, and additional personnel training. No new findings were identified in the inspectors’ review. This issue was found to be of minor significance because no actual loss of safety function occurred and therefore was found not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. The licensee documented the issue in CR 07-25695. A licensee identified violation associated with this issue is documented in Section 4OA7 of this report. This LER is closed.

.3 Train Derailment and Explosion

a. Inspection Scope

On October 10, 2007, the control room was notified that a train wreck had occurred near the plant. A train that was transporting oil and other combustible fluids had derailed, exploded, and caught fire. The location of the incident was determined to be about 10 miles from the plant and one mile from an electrical transmission line. Local officials evacuated residents within about a mile of the wreck. Local responders established a perimeter around the area and closed several roads. The inspectors reviewed licensee actions and communications associated with the event to determine whether the actions were in accordance with procedures and TS requirements. In addition, the inspectors reviewed licensee actions to assess potential impacts of the event on the site’s emergency response readiness.

b. Findings

No findings of significance were identified.

.4 Fuel Channel Drop

a. Inspection Scope

On October 18, 2007, licensee personnel were conducting movements of fuel channels in the spent fuel pool as part of a spent fuel pool cleanup project. During a movement evolution, a fuel channel became dislodged from the bridge grapple device used to lift the channel. The channel was inside the pool and above the pool fuel racks when the incident occurred. The channel dropped down, impacted empty spent fuel pool fuel racks and then toppled over onto the top of several spent fuel assemblies. The inspectors responded to the fuel handling building and observed the licensee's response to the event. The inspectors reviewed the licensee's actions to determine whether procedural and TS requirements were met.

b. Findings

A finding and an NCV associated with this event is documented in Section 4OA2 of this report.

.5 Hot Surge Tank Level Control and Loss of Heater #4

a. Inspection Scope

On October 25, 2007, operators responded to hot surge tank level fluctuations and a loss of extraction steam to heater #4. Operators entered Off-Normal Instruction C-51, "Unplanned Change In Reactor Power or Reactivity", Revision 24, and reduced reactor power to about 95 percent. The cause of the event was determined to be a failed hot surge tank level controller. The inspectors responded to the control room. The inspectors observed operator actions in the control room in response to the event to determine whether the actions were consistent with TS and approved procedures.

b. Findings

No findings of significance were identified.

.6 Reactor scram due to Digital Feedwater Level Control System failure followed by a failure of Reactor Core Isolation Cooling

a. Inspection Scope

On November 28, 2007, the inspectors observed licensee actions in response to a scram with complications. The digital feedwater level control system experienced a loss of two power supplies. This caused a loss of feedwater, main turbine trip, and reactor scram due to an erroneous reactor vessel water level 8 signal. The loss of feedwater caused an actual reactor vessel water level 2, which initiated both RCIC and high pressure core spray (HPCS) for reactor vessel water level control. RCIC tripped approximately 13 seconds after initiation due to low suction pressure, and reactor vessel control was maintained using HPCS. The inspectors observed licensee personnel shutdown the plant to Mode 4. A Special Inspection Team was chartered to investigate this event, and the results are documented in IR 05000440/2007010.

b.1 Unresolved Item (URI) 05000440/2007005-10: Adequacy of Reactor Core Isolation Cooling System Surveillance Testing.

At the end of the inspection period, the inspectors continued to evaluate the adequacy of RCIC surveillance test procedures. A contributing cause of the November 28, 2007, RCIC failure was determined to be an improperly tuned flow controller. The controller settings were established in January 2006 and the RCIC system had passed routine surveillance testing criteria since that time without identification of the condition. RCIC testing typically relied on a suction and return flow path to the condensate storage tank. On November 28, 2007, RCIC failed to perform as designed when called upon to inject from the suppression pool to the reactor vessel.

b.2 Unresolved Item (URI) 05000440/2007005-11: Adequacy of the Reactor Core Isolation Cooling System Flow Controller Tuning Procedures.

At the end of the inspection period, the inspectors continued to evaluate the adequacy of the RCIC flow controller tuning procedure. A contributing cause of the November 28, 2007, RCIC failure was determined to be an improperly tuned flow controller. Following this failure, the licensee revised the tuning of the RCIC flow controller, tested the new settings, and determined that RCIC was operable on December 10, 2007. On December 12, 2007, the licensee declared RCIC inoperable due to questions over the appropriateness of the flow controller settings and whether the settings provided a sufficiently over-damped response for conditions of RCIC injection to the reactor vessel from the suppression pool. The licensee again revised the RCIC flow controller settings and returned the settings to values associated with successful injection testing to the reactor during baseline pre-startup testing. Following additional testing using the condensate storage tank and further evaluation, the licensee declared RCIC operable again on December 21, 2007.

4OA5 Other Activities

Closed URI 05000440/2007004-01: Loss of Decay Heat Removal Resulting from Failure to Follow Procedures.

Introduction: A Green finding of very low safety significance and an NCV of TS 5.4, "Procedures," was self-revealed when a loss of cooling water flow to the reactor occurred while the reactor was shutdown on July 11, 2007. A maintenance technician failed to adhere to procedures while performing a surveillance test and performed an action that caused the 'B' RHR pump to trip.

Description: On July 11, 2007, the plant was shutdown in Mode 4 with the 'B' RHR loop in service providing decay heat removal for the reactor vessel. A maintenance technician was performing a surveillance test associated with the RCIC steam line flow high instrument channel. At about 11:13 p.m. the technician disconnected a wire for a relay associated with a RCIC system isolation function. This caused the relay to change state. The licensee determined that when the affected relay changed state and de-energized, it created an inductive electrical transient that affected the relay power supply. The affected power supply wires were physically tied to the power wires for an optical isolator associated with a relay for the 'B' RHR pump trip circuit. The electrical transient resulted in the actuation of the optical isolator and the trip of the 'B' RHR pump.

The technician was performing the surveillance test using SVI-E31-T5395B, “Reactor Core Isolation Cooling (RCIC) Steam Line High Channel Functional For 1E31-N0684-B,” Revision 2. Step 5.1.14 of the procedure required the technician to lift the wire lead associated with the RCIC system isolation function if a status light indicated RCIC was not isolated, and it required the technician to mark the step as “not applicable” if the status light indicated RCIC was isolated. While performing this step, the technician followed the procedure path for the system in normal operations mode, when the system was actually isolated.

The licensee concluded that the technician had performed the test in the past under different plant conditions, most often when the plant was in Mode 1 and RCIC was not isolated. They concluded that the technician’s past experience performing the test under a different plant configuration may have contributed to the procedure performance error.

The licensee determined that the design of the affected electrical panel, which placed the RCIC isolation and RHR pump wiring in close proximity, contributed to the RHR pump trip. The licensee further determined that the optical isolator, that initiated the RHR pump trip, was degraded and that this made it susceptible to the electrical noise that resulted when the technician disconnected the wire for the RCIC isolation circuit.

As part of their immediate corrective actions, licensee personnel restored shutdown cooling water flow to the reactor by placing the ‘A’ RHR loop in service and entered the issue into the corrective action program. Subsequently, the licensee conducted additional training on human performance tools, initiated procedure revisions, planned to replace the affected optical isolator, and began a review to produce design change to address the panel wiring configuration issue.

<u>Analysis</u>: The inspectors determined that the failure of the licensee maintenance technician to adhere to surveillance test procedures affecting the safety-related RCIC system was a performance deficiency warranting a significance evaluation. The inspectors concluded that the finding was greater than minor in accordance with Appendix B, “Issue Screening,” of IMC 0612, “Power Reactor Inspection Reports,” dated September 20, 2007. The finding was associated with the equipment performance attribute of the reactor safety Initiating Events Cornerstone and affected the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, the finding resulted in a loss of cooling water flow to the reactor while the reactor was shutdown.

The licensee concluded that the technician’s history of performing the RCIC test under a different plant configuration contributed to the technician’s failure to perform the procedure as written. The inspectors noted that the surveillance test was typically performed while the plant was in Mode 1 with RCIC not isolated and that the test was less frequently performed in Mode 4 with RCIC isolated. The inspectors determined that a primary cause of this finding was related to the cross-cutting area of Human Performance per IMC 0305 H.3(b) because the organization failed to appropriately coordinate the work activity by keeping personnel apprised of the operational impact of the work activity and the plant conditions that may affect it. The inspectors determined that the implications of performing the test procedure while in Mode 4 with RCIC isolated were not fully realized by the maintenance technician prior to the performance of the work.

Phase 1 Assessment

Since the plant was shutdown, the inspectors evaluated this finding in accordance with NRC IMC 0609 Appendix G, "Shutdown Operations Significant Determination Process (SDP)," February 28, 2005. As part of the SDP, the inspectors assess conditions or events that represent a loss of control. Table 1 in Appendix G lists criteria for losses of control. If the criteria are met, then the finding needs to be quantitatively assessed via a Phase 2 analysis. The inspectors concluded that the criterion for "Loss of Thermal Margin (PWRs and BWRs) was met since the margin to boil was estimated at 0.3 (criterion met if greater than 0.2).

Phase 2 Assessment

The Region III Senior Reactor Analyst (SRA) performed the Phase 2 assessment using Appendix G, Attachment 3, "Phase 2 Significance Determination Process Template for BWR During Shutdown." The SRA determined this issue to be a precursor to an initiating event; specifically, it could lead to a loss of the decay heat removal function. Loss of RHR (LORHR) was the initiating event. The plant operational state (POS) was determined to be "POS 1" (vessel head on and RCS closed). The initiating event likelihood for the LORHR using Table 3, Initiating Event Likelihoods (IELs) for LORHR Precursors," was zero, since a loss of the operating train of RHR occurred.

Using Appendix G, Attachment 3, Worksheet 4, "SDP Worksheet for a BWR Plant - Loss of Operating Train of RHR in POS 1 (Head On)," the analyst made adjustments to the remaining mitigation capability credits to reflect equipment availability and time available to complete tasks prior to core damage.

The most significant core damage sequences were:

- LORHR followed by failure to recover the RHR function, and failure of operators to vent containment; and
- LORHR followed by failure to recover the RHR function, and failure of low and high pressure injection.

Both sequences had risk significance of "6" (i.e., delta core damage frequency 1E-6). Therefore, the finding was evaluated for its potential risk contribution due to large early release frequency in accordance with IMC 0609, Appendix H.

For the evaluation of risk significance during shutdown, only the period within eight days of the beginning of the outage is considered. After eight days, it is assumed that the short-lived, volatile isotopes that are principally responsible for early health effects have decayed sufficiently such that the finding would not contribute to large early release frequency. Therefore, the delta core damage frequency for this Phase 2 assessment remained at 1E-6 (White). A more refined Phase 3 risk assessment was performed to address the inherent conservatisms with the Phase 2 assessment.

Phase 3 Assessment

The Phase 3 risk assessment was performed by a Senior Reliability and Risk Analyst from the Office of Nuclear Reactor Regulation, with assistance from the Region III SRA using the following references:

- SAPHIRE/GEM Model (Version 7.27);
- Perry Simplified Plant Analysis Risk (SPAR) Model (Version 3.21);
- RASP Internal Events Handbook;
- NUMARC 91-06, "Guidelines for Industry Actions o Assess Shutdown Management," December 1991;
- NUREG/CR-6883, "The SPAR-H Human Analysis Method," August 2005;
- NUREG/CR-1792, "Good Practices for Implementing Human Reliability Analysis," April 2005;
- NUREG/CR-6595 Revision 1, "An Approach for Estimating the Frequencies of Various Containment Failure Modes and Bypass Events," October 2004;
- GE SIL-357, "Control of Reactor Vessel Temperature/Pressure during Shutdown," June 1981.

For this Phase 3 assessment, IMC 0609, Appendix G, Attachment 3, directs the analyst to access the significance by calculating an instantaneous conditional core damage probability. Because no low power/shutdown SPAR model exists for Perry, the analyst modified the at-power Perry SPAR model to replicate the plant conditions at shutdown. Shutdown operation is highly dependent on operator actions since most of the required actions are manual. Detailed analyses were conducted to properly characterize the many potentially required manual actions.

Standard Probabilistic Risk Assessment (PRA) practices direct that, in cutsets with multiple human error probabilities (HEPs), a justifiable minimum value for the multiple HEPs should be specified.

NUREG-1792, "*Good Practices for Implementing Human Reliability Analysis*," recommended a cutoff of 1E-5. The analyst used this recommended cutoff for cutsets where all HEPs occurred within the first 15 hours after event initiation. The analyst deviated from this approach when the time available was sufficiently long.

The dominant core damage cutsets involved LORHR injection; successful depressurization and actuation of low pressure ECCS, or failure to depressurize and successful high pressure ECCS; failure to vent containment; and subsequent containment failure.

Operators must vent containment to relieve pressure caused by heatup of the suppression pool due to operation of safety/relief valves and ECCS pumps. The failure to vent containment was postulated to lead to its failure due to overpressure, which in turn would fail all injection.

The resultant instantaneous conditional core damage probability was on the order of 5.0E-7, which represents a finding of very low (i.e., Green) risk significance. Because this risk assessment involved an actual event during which no external events occurred, there was no contribution to risk from external events.

Enforcement: Technical Specification 5.4, "Procedures," required the implementation of the applicable procedures recommended in Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operation)," Revision 2, dated February 1978. Regulatory Guide 1.33, Appendix A, Part 8b, recommended procedures for surveillance testing of the RCIC system. Licensee procedure SVI-E31-T5395B, Revision 2, step 5.1.14 required personnel to lift a wire lead associated with the RCIC system isolation function if a status light indicated RCIC was not isolated, and it required the technician to mark the step as "not applicable" if the status light indicated RCIC was isolated. Contrary to this requirement, on July 11, 2007, licensee personnel lifted the wire lead when the status light indicated RCIC was isolated. This led to an electrical transient in a control panel housing RCIC system and RHR pump circuits and resulted in a loss of shutdown cooling water flow to the reactor. However, because of the very low safety significance of the issue and because the issue has been entered into the licensee's corrective action program (CR 07-23350), the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy. (NCV 05000440/2007005-08)

4OA6 Meetings

.1 Exit Meeting

The inspectors presented the inspection results to the Site Vice President, Mr. Barry Allen and other members of licensee management on January 10, 2007. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

.2 Interim Exit Meetings

- EP inspection with Mr. B. Allen on October 19, 2007;
- Access Control to Radiologically Significant Areas and the ALARA Planning and Controls Program with Mr. B. Allen, October 26, 2007;
- EP inspection with Mr. J. Beavers on December 11, 2007;
- Radioactive Effluents with Mr. B. Allen on December 14, 2007; and
- Biennial Operator Requalification Program Inspection with Mr. R. Gemberling on December 20, 2007.

4OA7 Licensee-Identified Violations

The following violations of very low safety significance (Green) were identified by the licensee and are violations of NRC requirements, which meets the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as NCVs.

**Cornerstone: Mitigating Systems**

Technical Specification 3.0.4, "Limiting Condition for Operation (LCO) Applicability," required that a mode change cannot occur when an LCO is not met, unless certain conditions are fulfilled. Contrary to this requirement, on July 23, 2007, the plant changed modes when TS LCO 3.5.1 requirements A.1, B.1, B.2, and C.1 were not met. On August 26, 2007, the licensee discovered a section of containment grating to be unsecured. The grating under certain conditions could impact the ECCS suction strainer associated with the HPCS, RHR ‘A’, and RHR ‘B’ pump suctions. On August 27, 2007, the licensee identified this vulnerability and entered the applicable TS LCO 3.5.1 requirements. The licensee concluded that the condition had existed since their last outage in July 2007, when they performed work to repair a reactor recirculation pump motor prior to startup. On July 23, 2007, the plant restarted from Mode 4 to Mode 2, then to Mode 1. Not knowing that TS LCO 3.5.1 was not met, licensee personnel allowed the mode changes. As part of their immediate corrective actions, the licensee repaired the condition and entered it into their corrective action program. The finding was determined to be of very low safety significance because it did not represent an actual loss of safety function.

**Cornerstone: Occupational Radiation Safety**

Technical Specification 5.7.2 states that areas accessible to personnel with radiation levels such that a major portion of the body could receive in 1 hour a dose greater than or equal to 1000 mRem shall be provided with locked or continuously guarded doors to prevent unauthorized entry. Contrary to the above, on May 5, 2007, an area in Intermediate Building elevation 574', by the control rod drive suction filter, was found to have dose rates that exceeded 1000 mRem/Hr at 30cm from the radiation source without the required access controls. This incident was identified by, and documented in the licensee’s corrective action program as CR 07-20033; and immediate corrective actions were taken to establish appropriate access control. The finding was of very low safety significance because it did not involve ALARA planning or work controls, there was no overexposure or substantial potential for an overexposure to the worker, nor was the licensee’s ability to assess worker dose compromised.

ATTACHMENT: SUPPLEMENTAL INFORMATION

## SUPPLEMENTAL INFORMATION

## KEY POINTS OF CONTACT

Licensee

B. Allen, Vice President Nuclear
K. Krueger, Plant General Manager
M. Alfonso, Chemistry Manager
J. Beavers, Emergency Preparedness Senior Planner
N. Bonner, Fleet Oversight
M. Brogan, Operations Superintendent
A. Cayia, Performance Improvement Director
J. Clark, Emergency Preparedness
R. Coad, Work Management Manager
R. Collings, Fleet Emergency Preparedness
R. Dame, Outage Manager
C. Elberfeld, Nuclear Compliance Supervisor
D. Evans, Operations Manager
K. Freeman, Radiation Protection Supervisor
R. Gemberling, License Operator Requalification Training Lead
E. Gordon, Radiation Protection Operational Superintendent
J. Gorman, Human Resources Manager
V. Higaki, Corporate Emergency Preparedness Manager
C. Jenkins, Emergency Preparedness Senior Specialist
M. Koberling, Plant and Equipment Reliability Manager
L. Lindrose, Security Manager
B. Luthanen, Chemistry Supervisor
M. Wesley, Maintenance Manager
J. Pelcic, Nuclear Compliance Engineer
L. Schlaugh, Emergency Preparedness Specialist
J. Shaw, Site Engineering Director
F. Smith, Emergency Planning Manager
T. Stec, Nuclear Compliance Engineer
S. Thomas, Radiation Protection Manger
L. Vanderhorst, Emergency Preparedness Senior Specialist
K. Cimorelli, Maintenance Director

State of Ohio

J. Wills, Department of Public Safety Emergency Management Agency

Nuclear Regulatory Commission

D. Passehl
S. Sheldon, DRS
C. Brown, DRS

## LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

| | | |
|---|---|---|
| 05000440/2007005-01 | NCV | Failure to Adhere to Procedures for Scaffold Affecting Reactor Core Isolation Cooling (Section 1R04.1) |
| 05000440/2007005-02 | NCV | Failure to Identify a Condition Adverse to Quality Associated with Scaffolding Contacting the Reactor Core Isolation Cooling System (Section 1R04.2) |
| 05000440/2007005-03 | NCV | Failure to Control RCIC Post Maintenance Testing (Section 1R19) |
| 05000440/2007005-04 | NCV | Failure to Develop an Accurate Dose Estimate for Scaffolding Work and to Maintain Workers' Doses ALARA (Section 2OS2.3) |
| 05000440/2007005-05 | NCV | Failure to Take Prompt Corrective Action to Address Extent-of-Condition for Nonconforming Conditions Affecting the Division 1 EDG (Section 4OA2.3) |
| 05000440/2007005-06 | FIN | Failure of Design Control Leading to Drop of Fuel Channel Onto Spent Fuel (Section 4OA2.4) |
| 05000440/2007005-07 | NCV | Failure to Correct Lack of an Alternate Decay Heat Removal System in a Timely Manner (Section 4OA3.1) |
| 05000440/2007005-08 | NCV | Failure to Adhere to Procedures Results in Temporary Loss of Decay Heat Removal (Section 4OA5) |

Opened

| | | |
|---|---|---|
| 05000440/2007005-9 | URI | Adequacy of Maintenance Associated with Emergency Service Water 'B' Strainer Failure (Section 1R19.2) |
| 05000440/2007005-10 | URI | Adequacy of Reactor Core Isolation Cooling System Surveillance Testing (Section 4OA3.6b.1) |
| 05000440/2007005-11 | URI | Adequacy of Reactor Core Isolation Cooling System Flow Controller Tuning Procedures (Section 4OA3.6b.2) |

Closed

| | | |
|---|---|---|
| 05000440/2007004-01 | URI | Loss of Decay Heat Removal Resulting From Failure to Follow Procedures (Section 4OA5) |
| 05000440/2007-002-00 | LER | Shutdown Cooling Pump Trip Results in Operation Prohibited by Technical Specifications (Section 4OA3.1) |
| 05000440/2007-003-00 | LER | Improper Containment Floor Grating Installation Results In Unanalyzed Condition (Section 4OA3.2) |

Discussed

| | | |
|---|---|---|
| 05000440/2005002-12 | NCV | Inadequate Implementation of TS 3.4.10 for Alternate Decay Heat Removal (Section 4OA3.6) |

Updated

None

## 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.

1R04 Equipment Alignment

Work Order 200292539
GCI-0016, "Scaffolding Erection, Modification or Dismantling Guidelines," Revision 10.
CR 07-31437; Housekeeping and Potential Scaffold Issues In RCIC Room; dated December 12, 2007
CR 07-31871; AEGTS B Discharge Damper Is Not Functioning Correctly; dated December 21, 2007
CR 07-31923; M15-F070B Damper Failure; dated December 22, 2007
CR 07-31994; Emergency Service Water Pump Discharge; dated December 28, 2007
VLI-P45; Emergency Service Water System; Revision 7

1R05 Fire Protection

FPI-1DG; Diesel Generator Building; Revision 5
FPI-TPB; Turbine Power Building; Revision 3
CR 07-28758; NRC ID Argon Bottle Not Properly Restrained; dated October 17, 2007
FPI-TPB; Turbine Power Building, Rev. 3
FPI-0CC; Control Complex, Rev 6
FPI-0EW; Emergency Service Water Pump House; Revision 4

1R06 Flood Protection Measures

CR 93082; Flooding Requirements of ECCS Rooms, Dated April 6, 1993
PY-DIDR-041; Penetration Seal Review for Flooding of ECCS and RCIC Rooms, Rev. 9
Design Verification Record for Calculation JL-125, dated April 3, 1993
Design Verification Record for Calculation JL-126, dated June 15, 1993
Drawing 911-0617-00000; Auxiliary Building Drains, Rev. F WO 200286880; Floor and Equipment Drains; dated October 25, 2007
CR 07-28352; Floor Drain Back-Up During Performance of Fire Protection Header Fill and Vent; dated October 11, 2007
CR 93082; Flooding Requirements of ECCS Rooms, Dated April 6, 1993
PY-DIDR-041; Penetration Seal Review for Flooding of ECCS and RCIC Rooms, Rev. 9
Design Verification Record for Calculation JL-125, dated April 3, 1993
Design Verification Record for Calculation JL-126, dated June 15, 1993
Drawing 911-0617-00000; Auxiliary Building Drains, Rev. F

1R07 Heat Sink Performance

Calculation Addendum R46-024; Div 2 Emergency Diesel Generator Jacket Water Heat Exchanger Performance Test Evaluation 9/18/2003; Revision 0 Addendum A-01; dated June 23, 2006

PTI-R46-P0001B; Div 2 Emergency Diesel Generator Jacket Water Heat Exchanger Performance; Revision 1

1R11 Operator License Qualification

OT-3070-RP6A Scenario; dated December 10, 2007
OT-3070-RP2D Scenario; dated December 10, 2007
December 10, 2007 Overall Dynamic Simulator Individual Evaluations
December 11, 2007 Job Performance Measure Evaluation Record Sheets
Perry Licensed Operator Requalification Program Results

1R12 Maintenance Effectiveness

CR 07-27856; Instrument Air Compressor Trip; dated October 4, 2007
CR 06-03258; Unit 2 Instrument Air Compressor Has an Oil Leak; dated July 22, 2006
CR 07-12771; Air Leak In yard Near Fuel Oil Pump House – Repeat Maintenance; dated January 16, 2007
CR 07-13686; Unit 2 Instrument Air Dryer 3B Malfunction; dated January 30, 2007
CR 07-12660; 1P52D0003B Instrument Air Dryer Repeat Maintenance; January 14, 2007
CR 06-8412; Instrument Air Dryer Preventative Maintenance; October 20, 2006
CR 05-08154; As Found Conditions On 1P51C0001; dated December 23, 2005
CR 06-01922; U1 Service Air Compressor Tripped on High Vibration; dated May 1, 2006
CR 06-00394; Valve Found Out Of Position; dated January 26, 2006
Perry Nuclear Power Plant System Health Report 2007-02; Service and Instrument Air
CR 06-11339; Manual Scram – Instrument Air Joint Failure leading To Loss of Instrument Air; dated December 12, 2006
Perry Nuclear Power Plant System Health Report 2007-02; Fuel Handling and Vessel Service Equipment
CR 07-31602; Controller 1C61R0001 Voltage High Limit Changed From Value Set In Control Room; dated December 16, 2007
CR 07-14879 Cause Analysis; RCIC Controller Drift; dated March 12, 2007
Calculation EQ-195; Qualified Life Of Bailey Controls 701 Controller; dated December 20, 2007

1R13 Maintenance Risk Assessments and Emergent Work Control

Perry Risk Assessment for the period October 8 thru October 14
Perry Work Implementation Schedule for the period October 9 thru October 10
Perry Work Implementation Schedule for the period October 10 thru October 11
Perry Work Implementation Schedule; Week 07; Period 2
On-Line Probabilistic Risk Assessment; Period 2 Week 1; Revision 0
PDB-R0001; Plant Data Book; Revision 24
On-Line Probabilistic Risk Assessment; Period 2 Week 12; Revision 0
Perry Work Implementation Schedule; Week 12; Period 2
Div. 2 EDG Unavailable due to CO2 system work
Perry Risk Assessment for the period October 8 thru October 14
Perry Work Implementation Schedule for the period October 9 thru October 10
Perry Work Implementation Schedule for the period October 10 thru October 11

1R15 Operability Evaluations

CR 07-27853; Incorrect Torque on Flow Control Valve Actuator Hydraulic Lines, dated October 4, 2007
CR 07-27886; Missed Operability Assessment, dated October 5, 2007
CR 07-28746; Additional Concerns with Bolt Torque for RECIRC Flow Control Valves, dated October 17, 2007
Functional Assessment for CR 0728746, Rev. 0
PY-PMI-0112; Greer Hydraulic Actuator Removal and Installation, Rev. 5
CR 07-29242; EDG Hallway Inspections Not Performed As Required; dated October 26, 2007
CR 07-29597; Unusual Noise on CR Emergency Recirc Fan 0M26C0001B; dated November 2, 2007
CR 07-30676 Operability Determination; HPCS ASME Fatigue Limits; dated December 3, 2007
CR 07-30660 Immediate Investigation; RCIC Tripped On Low Suction Pressure; dated December 4, 2007
CR 07-27853; Incorrect Torque on Flow Control Valve Actuator Hydraulic Lines, dated October 4, 2007
CR 07-27886; Missed Operability Assessment, dated October 5, 2007
CR 07-28746; Additional Concerns With Bolt Torque for RECIRC Flow Control Valves, dated October 17, 2007
Functional Assessment for CR 07-28746, Rev. 0
PY-PMI-0112; Greer Hydraulic Actuator Removal and Installation, Rev. 5
CR 07-30922; Seat Torque Valve Closing Value Exceeds Maximum Allowable; dated December 2, 2007
NOP-OP-1010-01; ODMI Recommendation Sheet – Decision Process for Plant Startup and RCIC Testing; Revision 0
CR 07-30660; Reactor Core Isolation Cooling Immediate Investigation; dated December 7, 2007
CR 07-31488; RCIC Procedure Change; dated December 13, 2007
CR 07-31900; NRC Questioned: Information In RCIC Operability Basis; dated December 21, 2007

1R19 Post-Maintenance Testing

CR 07-27566; Incorrect Post Maintenance Test Specified in Order, dated October 2007
Perry Nuclear Power Plant, Plant Health Report, 2007-02, dated September 21, 2007
PY-SOI-M51/56; Combustible Gas Control System and Hydrogen Igniters, Rev. 14
CR 07-28321; High Noise/Vibration on 1M15C0001A, dated October 11,2007
CR 07-18187; Discovered M15 A was Tagged for Work Which Is Not Allowed Per PAP-1925, dated April 11, 2007
CR 06-9407; Bearing Identification and Use, dated November 3, 2006
CR 06-9466; Original Deficiency AEGTS Fan A, dated November 3, 2006
WO 200285161; AEGTS Fan A Repairs, dated October 11, 2007
WO 200285188; AEGTS Fan A Repairs, dated October 13, 2007
WO 200104185; Division 3 DG Room Supply Fan; dated October 18, 2007
CR 07-28688; 1M43C001C Failed PMT Due To Possible Induced Voltage; dated October 16, 2007
CR 07-27566; Incorrect Post Maintenance Test Specified in Order, dated October 2007
Perry Nuclear Power Plant, Plant Health Report, 2007-02, dated September 21, 2007
PY-SOI-M51/56; Combustible Gas Control System and Hydrogen Igniters, Rev. 14

CR 07-28321; High Noise/Vibration on 1M15C0001A, dated October 11, 2007
CR 07-18187; Discovered M15 A Was Tagged for Work Which Is Not Allowed Per PAP-1925, dated April 11, 2007
CR 06-9407; Bearing Identification and Use, dated November 3, 2006
CR 06-9466; Original Deficiency AEGTS Fan A, dated November 3, 2006
WO 200285161; AGETS Fan A Repairs, dated October 11, 2007
WO 200285188; AGETS Fan A Repairs, dated October 13, 2007
CR 07-30937; Documentation of Conditions of CRDM 42-31 O-rings and Flange; dated December 4, 2007
Work Order 200292539
WO 200292539; Winter 2007 Post Scram RCIC Testing/Tuning; dated December 10, 2007
CR 07-31137; Information Provided In An Order Was Inaccurate; dated December 6, 2007
CR 07-31601; RCIC Acceptance Criteria Not Met During Controller Tuning, Evaluate Impact; dated December 16, 2007
CR 07-31602; Controller 1C61R001 Voltage High Limit Changed from Value Set In Control Room; dated December 16, 2007
WO 200188470; Inspect ESW B Discharge Strainer Internals; dated April 20, 2007
Control Room Operator Logs; dated December 27, 2007

1R20 Outage Activities

PYBP-SITE-0019; Post Scram Restart Report; dated November 30, 2007
IOI-4; Shutdown; Revision 12
IOI-8; Shutdown By Manual Reactor Scram; Revision 5
CR 07-30660; RCIC System Tripped Shortly After Initiation; dated November 28, 2007
CR 07-30676; PY-PA-07-04: RPV and RCS Transients vs. ASME Fatigue Limits; dated November 28, 2007
CR 07-30703; Unplanned Scram Report for Automatic Reactor Scram Due To DFWCS
Malfunction; dated November 28, 2007
CR 07-30689; 2 Control Rods Did Not Have Both of Their Scram Valves Open When Reactor Scram; dated November 28, 2007
CR 07-30777; Unsat Valve Stroke for SVI-N27-T2001, Feedwater Leakage Control; dated November 30, 2007
CR 07-30755; Control Rod Display Full In Light Indication Post Scram; November 28, 2007
CR 07-30700; Motor Feed Pump Ran with No Minimum Flow; dated November 28, 2007
CR 07-30868; Required Procedure Change ONI-N36; dated December 2, 2007

1R22 Surveillance Testing

PY-SVI-E51T2001, RCIC Pump and Valve Operability Test, Rev. 27
PY-SVI-E22T1319; Diesel Generator Start and Load Division 3, Rev. 14
E22-029; (Calculation) HPCS Pump Test Acceptance Criteria, Rev. 7
PY-SVI-E22-T2001; HPCS Pump and Valve Operability Test, Rev. 22
Perry Nuclear Power Plant, Plant Health Report 200702
PY-SVI-C51T0030G; APRM G Channel Calibration for 1C51-K605G, Rev. 8
Perry Nuclear Power Plant, Plant Health Report 200702
CR 07-30712; Evaluate RX Bottom Head Drain Cooldown/Heatup Post Scram 1-07-005; dated November 29, 2007
SVI-B21-T1176; RCS Heatup and Cooldown Surveillance; Revision 10

PY-SVI-E22T1319; Diesel Generator Start and Load Division 3, Rev. 14
E22-029; (Calculation) HPCS Pump Test Acceptance Criteria, Rev. 7
PY-SVI-E22-T2001; HPCS Pump and Valve Operability Test, Rev. 22
Perry Nuclear Power Plant, Plant Health Report 200702
SVI-E51T2001, RCIC Pump and Valve Operability Test, Rev. 27
SVI-C51T0030G; APRM G Channel Calibration for 1C51-K605G, Rev. 8
Perry Nuclear Power Plant, Plant Health Report 200702

1EP2 Alert and Notification System Evaluation

Federal Emergency Management Agency Prompt Alert and Notification System Approval Letter; dated September 8, 1986
Siren Alerting System for the Perry Nuclear Power Plant Design Report; dated June 1985
598RA2003 Alert and Notification System Self-Assessment Report; dated December 22, 2003
Standard Operating Procedure Siren Activation for Lake, Geauga, and Ashtabula Counties; dated January 2, 2007
PSI-0021; Prompt Alert System Maintenance Procedure; dated January 5, 2007
PYBP-EPU-0028; Prompt Alert Siren System Emergency Planning Zone Testing; dated December 15, 2004
Perry Prompt Alert Siren System History; dated 1996 through 2007
PNPP No. 6813; Perry Plant Prompt Alert System Annual Maintenance Checklist; dated October 2006 through February 2007
PNPP No. 6814; Perry Plant Prompt Alert System Maintenance Checklists; dated November 2005 through August 2007
PNPP No. 6816; Prompt Alert System Siren Test Reports; dated January 2006 through September 2007
CR 07-20930; Siren Number L17 Did Not Receive the Test Signal; dated May 21, 2007
CR 07-20167; Siren Number L4 Indicated a Failure to Rotate; dated May 8, 2007
CR 06-02557; Concern of Potential Ineffective Alert and Notification System; dated June 5, 2007
CR 06-01658; Emergency Alert and Notification System Test Partial Activation Failure; dated April 12, 2006

1EP3 Emergency Response Organization Staffing and Augmentation System

Emergency Plan for Perry Nuclear Power Plant; Section 5; Organizational Control of Emergencies; Revision 27
Perry Emergency Telephone Directory; Section 7; Emergency Response Organization; Revision 2007-3
EPI-A2; Emergency Actions Based on Event Classification; Revision 13
EPI-B1; Emergency Notification System; Revision 19
PSI-0022; Emergency Plan Training Program; Revision 2
PSI-0032; Attachment 1; Notification of Key Plant Personnel, Emergency Pager Personnel Checklist Results; dated June 11, 2007
PTI-GEN-P0003; Quarterly Testing of the Emergency Pager System; dated September 20, 2007, and January 27, 2007
Emergency Response Organization OPX Pager Test Results; dated October 20, 2007
Unannounced Pager Test Results; dated September 27, 2006
Emergency Response Organization Drive-In Drills; dated April 6, 2006, and March 21, 2006
CR 07-22015; Emergency Response Weekly Pager Test Results; dated June 13, 2007

1EP4 Emergency Action Level and Emergency Plan Changes

Perry Nuclear Power Plant Emergency Plan; Revisions 26 and 27

1EP5 Correction of Emergency Preparedness Weaknesses

MS-C-06-12-24; Quality Assurance Audit Report, Emergency Preparedness; dated February 12, 2007
PY-SA-07-100; Snap-Shot Assessment Report, EP Baseline Pre-Inspection Assessment; dated October 12, 2007
PY-C-06-02; FENOC Oversight Quality Field Observation, Tri-County Directors Meeting; dated April 19, 2006
October 24, 2006 Evaluated Exercise Documents and Records
Emergency Plan Declared Alert on February 11, 2007 Report; dated March 6, 2006
CR-11901; Minor Administrative Error on the Initial Notification Form Used during Licensed Operator Requalification; dated December 27, 2006
CR 06-08830; Core Status Assessment and Clad Damage Determination Confusion in 2006 Evaluated Exercise; dated October 24, 2006
CR 06-08825; 2006 Evaluated Exercise Loss of Communications with Radiation Monitoring Teams; dated October 26, 2006
CR 06-06259; ERO Training Drill Protective Action Recommendation Incorrect; dated September 12, 2006
CR 06-02781; Unusual Event Declared for Earthquake Occurrence at Perry Nuclear Power Plant; dated June 20, 2006
CR 06-00673; Difficulty Communicating Using Plant Two-Way Radios during February 11, 2006 Fire; dated February 11, 2006
CR 06-00670; Alert Declared for Fire in the Control Complex Due to Ventilation Fan 2B; dated February 11, 2006

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

CR 06-3094; Contractor Person Continue Working After Dose Rate Alarm; dated July 12, 2006
CR 06-3661; Turbine Building Elevator Problems Incurred During Rad Waste Shipment; dated August 11, 2006
CR 06-1454; DRD Experienced a Dose Rate ALARM and Went Unnoticed to the Worker; dated December 14, 2006
CR 07-7727; Cavity Manway Leakage Resulted in Increased Contamination in the Drywell; dated April 5, 2007
CR 07-17756; Dose Alarms While Working on Refuel Bridge; dated April 5, 2007
CR 07-18106; Excessive Jet Pump In-leakage Preventing Loop Draining and Full Chem Decon; dated April 10, 2007
CR 07-8170; Jet Pump Riser Transition Piece to Inlet Nozzle Leakage Observed on 10 Jet Pumps; dated April 11, 2007
CR 07-17995; PY-PA-07-02 Negative Trend in the Area of Scaffolding; dated April 9, 2007
CR 07-19167; Electronic Dosimeter Malfunctions During Use; dated April 24, 2007
CR 07-19406; RWP Violation; dated April 26, 2007
CR 07-19763; Higher Than Expected Dose Rates During Cavity Drain Down; dated May 1, 2007
CR 07-19784; Individual Entered High Radiation Area on Wrong RWP; dated May 1, 2007

CR 07-20033; Elevated Dose Rates (LHRA) Discovered in IB 574' on CRD Filters; dated May 5, 2007
CR 07-20087; Cavity Drain-down Line-up Affects Changes in Radiological Conditions; dated May 7, 2007
CR 07-20122; Non RAM Marked as RAM Found Outside the RCA; dated May 7, 2007
CR 07-21565; RFO-11 Lessons Learned; dated June 5, 2007
CR 07-26415; Container Identified Tied Off to handrail in Fuel Handling Building; dated September 11, 2007
CR 07-29213; Scaffold Dose for RFO-11 Exceeds Estimate by 150 percent; dated October 25, 2007
FENOC Fleet Oversight Audit Report PY-C-06-01; dated May 2006
FENOC Fleet Oversight Audit Report PY-C-06-02; dated August 2006
FENOC Fleet Oversight Audit Report PY-C-07-02; dated July 2007
HPI-D0001; Radiation and Contamination Survey Techniques; Revision 19
NOP-WM-7001; ALARA Program; Revision 01
NOP-WM-7002; Operational ALARA Program; Revision 01
NOP-WM-7003; Radiation Work Permit; Revision 03
NOP-WM-7025; High Radiation Area Program; Revision 01
PAP-0114; Radiation Protection Program; Revision 14
PDB-A0009; Expected Jet Pump Normalized dP and Flow Ranges; Revision 16
PDB-A0012; Recirc Drive Flow vs. Total Core Flow; Revision 15
Perry Nuclear Power Plant 2007 Excellence Plan; dated October 2007
Perry Nuclear Power Plant RFO11 Post Outage ALARA Report; dated October 2007
Perry Nuclear Power Plant Water Management Plan; Revision 0
Post-Job ALARA Review 07-019 (and associated RWPs) for Valve Repairs; dated October 2007
Post-Job ALARA Review 07-022 (and associated RWPs) for RFO-11 ALARA Activities; dated October 2007
Post-Job ALARA Review 07-031 (and associated RWPs) for Chemical Decontamination of the Reactor Recirculation and Reactor Water Clean-Up Systems; dated October 2007
Post-Job ALARA Review 07-040 (and associated RWPs) for RFO-11 Operations Activities; dated October 2007
Post-Job ALARA Review 07-041 (and associated RWPs) for RFO-11 I&C Activities; dated October 2007
Post-Job ALARA Review 07-044 (and associated RWPs) for RFO-11 Plant Maintenance Activities; dated October 2007
Post-Job ALARA Review 07-056 (and associated RWPs) for Scaffold Activities; dated October 2007
Post-Job ALARA Review 07-057 (and associated RWPs) for Snubbers; dated October 2007
RFO-11 Work Order Spreadsheet; Revision Master
RPI-0504; Radiation Protection Administrative Instructions; Revision 6
RPI-0122; Temporary Shielding Program; Revision 4
RPI-0316; Control of Permanent Plant Shielding and Radiation Base Point Surveys; Revision 4
RWP Totals List; dated October 2007
SOI-C11 (CRDH); Control Rod Drive Hydraulic System; Revision 17
Station ALARA Committee Meeting Minutes; dated Various 2007

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

CHI-0005; Miscellaneous Sampling Systems; Revision 9
CHI-0006; Radiation Monitoring Alarm Setpoint Determination; Revision 14

CHI-0007; Radiological Effluent Data Reduction; Revision 12
CHI-0053; Operation of the Gamma Spectroscopy System; Revisions 10 and 11
NOBP-LP-4012; NRC Performance Indicators; Revisions 1 and 2
NOP-LP-2001; Corrective Action Program; Revision 17
NOP-OP-3202; FENOC Radiochemistry Quality Control Program; Revision 3
PAP-0809; Radiological Environmental Contamination Response; Revision 3
PY-SVI-D17T8040; Unit 2 Plant Vent Effluent System and Sampler Flow Rate Monitor Calibration; dated August 2007
PY-SVI-1D17T8033; Unit 1 Vent Sampler Flow Rate Monitor Calibration; dated October 2007
PY-SVI-D17T8031; Unit 1 Vent Noble Gas Rad Monitor Calibration for 1D17-K786; dated September 2006
PY-SVI-D17T8034; Unit 1 Plant Vent Effluent System and Sampler Flow Rate Monitor Functional/Calibration; dated September 2007
PY-SVI-D17T8040; Unit 2 Plant Vent Effluent System and Sampler Flow rate Monitor Functional/Calibration; dated October 2007
PY-SVI-D17T8037; Unit 2 Vent Noble Gas Rad Monitor Calibration For 1D17-K786; dated June 2006
PY-SVI-D17T8002; LRW to ESW Rad Monitor Calibration for D17-K606; dated October 2007
PY-SVI-D17T8052; Off Gas Vent Sampler Flow Rate Monitor Calibration; dated April 2006
PY-SVI-D17T8050; Off Gas Vent Pipe Noble Gas Rad Monitor Calibration for 1D17-K836; dated July 2006
PY-SVI-D17T8043; TB/HB Vent Noble Gas Rad Monitor Calibration For 1D17-K856; dated August 2006
PY-SVI-D17T8047; TB/HB Vent Effluent System and Sampler Flow Rate Monitor Functional/Calibration; dated October 2007
PY-SVI-D17T8041; ESW Loop A Rad Monitor Channel Calibration for 1D17-K604; dated July 2006
PY-SVI-D17T8044; ESW Loop B Rad Monitor Channel Calibration for 1D17-K605; dated January 2007
PY-SVI-M15T1240A; Annulus Exhaust Gas Treatment System Train A Flow and Filter Operability Test; dated October 2006
PY-SVI-M15T1240B; Annulus Exhaust Gas Treatment System Train A Flow and Filter Operability Test; dated August 2007
PY-SVI-M15T3015; “A” Annulus Exhaust Gas Treatment Charcoal Adsorber Operability Test and Plenum Inspection; dated October 2006
PY-SVI-M15T3015; “B” Annulus Exhaust Gas Treatment Charcoal Adsorber Operability Test and Plenum Inspection; dated August 2007
PY-SVI-M26T1260A; Control Room Emergency Recirculation Subsystem A Flow and Filter Operability Test; dated November 2007
PY-SVI-M26T1260B; Control Room Emergency Recirculation Subsystem B Flow and Filter Operability Test; dated August 2007
PY-SVI-M26T3020; “A” Control Room Emergency Recirculation Charcoal Adsorber Operability Test and Plenum Inspection; dated November 2007
PY-SVI-M26T3020; “B” Control Room Emergency Recirculation Charcoal Adsorber Operability Test and Plenum Inspection; dated September 2007
PY-SVI-M40T5329A; Fuel Handling Building Ventilation Exhaust Flow and Filter Operability Test - A Train; dated July 2007
PY-SVI-M40T5329B; Fuel Handling Building Ventilation Exhaust Flow and Filter Operability Test - B Train (partial); dated November 2007
PY-SVI-M40T5329C; Fuel Handling Building Ventilation Exhaust Flow and Filter Operability Test - C Train; dated October 2007

PY-SVI-M40T5330; “A” Fuel Handling Building Ventilation Charcoal Adsorber Operability Test and Plenum Inspection; dated August 2007
PY-SVI-M40T5330; “B” Fuel Handling Building Ventilation Charcoal Adsorber Operability Test and Plenum Inspection; dated December 2007
SOI-D17; Airborne Radiation Monitoring Systems (Effluents); Revision 7
Calibration Status for Detector 1, Selected Geometries; selected dates 2007
FirstEnergy Groundwater Field Sampling Plan, Perry Nuclear Power Plant; dated August 2007
Inter-laboratory Comparisons; dated Second Quarter 2005-2006
CR 05-04184; Audit PY-C-05-02 REMP Portion of the ODCM has Some Discrepancies in the Maps; dated May 10, 2005
CR 05-05303; Response to WARF / RISB Ventilation Shutdown Questioned; dated July 7, 2005
CR 06-01615; RFA WARF Effluent Monitoring With Ventilation Secured; dated April 9, 2006
CR 06-01901; Accessability to a Locked High Radiation Area; dated May 1, 2006
CR 07-14399; Potential Tritium Issue From Fire System Leakage; dated February 9, 2007
CR 07-21559; Detectable Level of Tritium Found in ESW C Sample; dated June 6, 2007
CR 07-27410; Missed Sample on C ESW Run; dated September 19, 2007
CR 07-30487; D17A-K0606 Radwaste to ESW Failed to Alarm; dated November 22, 2007
CR 07-31335; Reactor Power Increase Without OCC Knowledge; dated December 11, 2007
Monthly Liquid Radwaste Releases; selected dates 2006-2007
Monthly Gaseous Effluent Releases; Totals Report; dated November 2007
Compensatory Sampling Data for Gaseous Releases; selected dates 2007
Compensatory Sampling Data for Liquid ESW Releases; selected dates 2007
Perry Nuclear Power Plant (PNPP) Annual Environmental and Effluent Release Reports; dated 2005 and 2006
Perry Nuclear Power Plant (PNPP) 10CFR 50.75g Files; selected dates 1994-2005
Perry Offsite Dose Calculation Manual; Revision 14

4OA1 Performance Indicator Verification

NEI 99-02; Regulatory Assessment Performance Indicator Guideline; Revision 5
Perry Safety System Functional Failure Data Sheets; April 2006 through June 2007
LER 05000440/2006-004; Oscillation Power Range Monitors Inoperable; Revision 0
NEI 99-02; Regulatory Assessment Performance Indicator Guideline; Revision 5
Perry Safety System Functional Failure Data Sheets; April 2006 through June 2007
Emergency Service Water Monthly Unavailability/Unreliability Data Sheets; July 2006 through June 2007
CR 07-14380; Review of Acceptance Criteria for Silt Buildup in Plant Intake Tunnels is Needed
CR 07-14665; ESW B Declared Inop
NEI 99-02; Regulatory Assessment Performance Indicator Guideline; Revision 5
Residual Heat Removal Monthly Unavailability/Unreliability Data Sheets; July 2006 through June 2007
CR 06-7480; NRC Performance Indicator Data May Be Incorrect
Surveillance Procedure SVI-E12-T0146; ECCS/LPCI Pump A Start Time Delay Relay Channel Functional/Calibration for 1E12A-K70A; Revision 4
Surveillance Procedure SVI-E12-T1194; LPCI Pump A Discharge Low Flow (Bypass) Channel Functional for 1E12-N652A; Revision 5
CR 07-0033; Elevated Dose Rates (LHRA) Discovered on IB 574' on CRD Filters; dated May 5, 2007
CR 07-9241; RP Occupational Dose Cornerstone NRC PI Not Reported in Second Quarter 2007; dated October 26, 2007
PYBP-RC-0004; NRC Performance Indicators; Revision 02

Alert and Notification System Reliability

NOBP-LP-4012-13; Alert and Notification System Reliability Results; dated October 2006 through June 2007
PNPP No. 6816; Prompt Alert System Siren Test Reports; dated October 2006 through June 2007

Emergency Response Organization Participation

NOBP-LP-4012-12; Emergency Response Organization Drill Participation Results; dated December 2006 through June 2007
PYBP-RC-0004; Appendix A; Data Provided Desktop, Emergency Response Organization Drill Participation; dated December 2006 through June 2007
Simulator Examination Summary Sheets; dated November 2006 through June 2007
Emergency Response Organization Exercise/Drill Attendance Sheets; dated October 2006 through June 2007

Drill and Exercise Performance

NOBP-LP-4012-11; Emergency Preparedness Drill/Exercise Performance Results; dated October 2006 through June 2007
PNPP No. 7794; Initial Notification Forms; dated October 2006 through June 2007
CR 07-25612; Emergency Action Level Incorrectly Declared during an Evaluated Scenario; dated August 20, 2007
CR 07-22097; EP Drill with Inappropriate Controller Prompt; dated June 14, 2007
CR 06-06310; ERO Training Drill Incorrect EAL Declaration; dated September 13, 2006

4OA2 Identification and Resolution of Problems

CR 07-30185; Div 1 DG Exhaust Valve Lifters Found Broken; dated November 15, 2007
CR 07-28851; Dropped Fuel Channel; dated November 12, 2007
CR 07-30279; Division 1 DG Cylinder Head Nuts As-Found Torque Values Outside Specified Range; dated November 16, 2007
CR 06-9890; Div 2 Diesel Gen Head Bolts Found Under Torqued; dated November 13, 2006

4OA3 Event Follow-Up

PY-ONI-C51; Unplanned Change in Reactor Power or Reactivity, Rev. 24
PY-ONI-N36; Loss of Feedwater Heating, Rev. 9
Spent Fuel Pool Work Release Plan; dated October 19, 2007
ONI-N36; Loss of Feedwater Heating; Revision 9
CR 07-30642; Plant Scram On Wednesday, 11-28-07; dated November 28, 2007
PY-ONI-C51; Unplanned Change in Reactor Power or Reactivity, Rev. 24
PY-ONI-N36; Loss of Feedwater Heating, Rev. 9

**LIST OF ACRONYMS USED**

| | |
|---|---|
| AEGTS | annulus exhaust gas treatment system |
| ALARA | As-Low-As-Is-Reasonably-Achievable |
| ANS | Alert and Notification System |
| CFR | Code of Federal Regulations |
| CR | condition report |
| DFI | Demand for Information |
| ECCS | emergency core cooling system |
| EDG | emergency diesel generator |
| EP | Emergency Preparedness |
| ERO | Emergency Response Organization |
| ESW | emergency service water |
| FENOC | FirstEnergy Nuclear Operating Company |
| FPI | Fire Protection Instruction |
| GCI | General Civil Instruction |
| HEP | human error probability |
| HPCS | high pressure core spray |
| IMC | Inspection Manual Chapter |
| IR | Inspection Report |
| ISRCG | In Storage Rack Channel Grapple |
| LCO | limiting condition for operation |
| LER | Licensee Event Report |
| LORHR | loss of residual heat removal |
| NCV | non-cited violation |
| NOP | Normal Operating Procedure |
| NRC | Nuclear Regulatory Commission |
| ODCM | Offsite Dose Calculation Manual |
| PAP | Perry Administrative Procedure |
| PI | Performance Indicator |
| PRA | Probabilistic Risk Assessment |
| RCIC | reactor core isolation cooling |
| RETS | Radiological Effluent Technical Specifications |
| RHR | residual heat removal |
| RSP | remote shutdown panel |
| RWP | Radiation Work Permit |
| SDP | Significance Determination Process |
| SOI | Standard Operating Instruction |
| SPAR | simplified plant analysis risk |
| SRA | Senior Reactor Analyst |
| SVI | Surveillance Instruction |
| TS | Technical Specification |
| UFSAR | Updated Final Safety Analysis Report |
| USAR | Updated Safety Analysis Report |
| URI | unresolved item |
| VLI | Valve Lineup Instruction |
| WO | work order |