October 24, 2004

Mr. Lew Myers
Chief Operating Officer
FirstEnergy Nuclear Operating Company
Perry Nuclear Power Plant
P. O. Box 97, A290
10 Center Road
Perry, OH 44081

SUBJECT: PERRY NUCLEAR POWER PLANT
NRC INTEGRATED INSPECTION REPORT 05000440/2004013

Dear Mr. Myers:

On September 30, 2004, 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 October 6, 2004, with you and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

Based on the results of this inspection, five NRC-identified findings and one self-revealed finding of very low safety significance, five of which involved violations of NRC requirements, were identified. However, because of their very low safety significance and because they have been entered into your corrective action program, the NRC is treating these findings as Non-Cited Violations in accordance with Section VI.A.1 of the NRC's Enforcement Policy. Additionally, licensee-identified violations which were determined to be of very low safety significance are listed in Section 4OA7 of this report.

If you contest the subject or severity of these Non-Cited Violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the Resident Inspector Office at the 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). ADAMS is accessible from the NRC Web site at **http://www.nrc.gov/reading-rm/adams.html** (the Public Electronic Reading Room).

Sincerely,

/RA/

Mark A. Ring, Chief
Branch 1
Division of Reactor Projects

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

Enclosure: Inspection Report 05000440/2004013
w/Attachment: Supplemental Information

cc w/encl: G. Leidich, President - FENOC
J. Hagan, Senior Vice President Engineering and Services, FENOC
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U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-440
License No:	NPF-58
Report No:	05000440/2004013
Licensee:	FirstEnergy Nuclear Operating Company (FENOC)
Facility:	Perry Nuclear Power Plant, Unit 1
Location:	P.O. Box 97 A210 Perry, OH 44081
Dates:	July 1 though September 30, 2004
Inspectors:	R. Powell, Senior Resident Inspector J. Ellegood, Resident Inspector J. House, Senior Radiation Specialist
Approved by:	M. Ring, Chief Branch 1 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000440/2004013; 07/01/2004 - 09/30/2004; Perry Nuclear Power Plant; Equipment Availability and Functional Capability; Post-Maintenance Testing; Surveillance Testing; Identification and Resolution of Problems; Other Activities.

This report covers a 3-month period of baseline inspection. The inspection was conducted by resident and regional health physics inspectors. This inspection identified six Green findings, five of which involved Non-Cited Violations (NCVs). The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be "Green" or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. Inspector-Identified and Self-Revealed Findings

Cornerstone: Mitigating Systems

Green. The inspectors identified a finding of very low safety significance for a violation of 10 CFR Part 50, Appendix B, Criterion XII. On July 7, 2004, the licensee failed to ensure that instrumentation used to measure diesel room temperature was calibrated with sufficient accuracy to ensure diesel generator starting air operability. After the inspectors discussed instrument accuracy with the licensee, the licensee implemented a reduced control temperature to account for instrument inaccuracy. The finding also affected the cross-cutting issue of Human Performance because the licensee's staff failed to recognize that instrument accuracy must be considered when establishing operating limits.

The inspectors determined that the licensee's failure to establish limits sufficient to ensure that limits in the operability evaluation were not exceeded was more than minor because it could reasonably be a precursor to a more significant event. The inspectors determined the finding did not involve the loss of safety function; and therefore, concluded that the finding was of very low safety significance. (Section 1REP.1.1)

- Green. The inspectors identified a finding of very low safety significance for a violation of 10 CFR Part 50, Appendix B, Criterion XVI, for failure to identify a condition adverse to quality. Specifically, the licensee identified fretting on emergency diesel generator (EDG) fuel oil return lines but did not measure the depth of the worst fret and erroneously declared operability based on a less severe fret. After the issue was brought to their attention on August 12, 2004, the licensee performed vibration measurements and performed calculations on the pipe to determine available margin. This analysis concluded that minimal margin existed and that the EDG could no longer be considered operable. The licensee declared the EDG inoperable, replaced the fretted section of pipe, and performed a successful post-maintenance test of the EDG. The primary cause of this finding was related to the cross-cutting area of Problem Identification and Resolution.

This finding was more than minor because it directly affected the mitigating system cornerstone objective of equipment reliability. The inspectors concluded that without repair, the pipe fret would have progressed to the point of fuel leakage and the diesel would not have been able to fulfill its mission. The inspectors concluded that there was no loss of safety function; therefore, the finding was of very low safety significance. (Section 1REP.1.2)

- Green. The inspectors identified a finding of very low safety significance for a violation of 10 CFR Part 50, Appendix B, Criterion XVI, for failure to identify a condition adverse to quality. Specifically, non-licensed operators failed to identify that the auxiliary switch in the control complex chilled water system 'A' chiller breaker cubicle was misaligned. After the condition was brought to the attention of the licensee on August 13, 2004, immediate corrective action was taken to align the switch later that same day. The primary cause of this finding was related to the cross-cutting area of Problem Identification and Resolution.

  The finding was more than minor because it could reasonably be a precursor to a more significant event. In fact, the issue was similar to the failure to properly align the high pressure core spray system pump breaker cell switch which resulted in the failure of the pump to start in October 2002. The inspectors determined the finding did not involve the loss of safety function; and therefore, concluded that the finding was of very low safety significance. (Section 1R19)

- Green. The inspectors identified a finding of very low safety significance for a violation of 10 CFR Part 50, Appendix B, Criterion XI. The inspectors determined that the combination of licensee testing protocol and established acceptance criteria was inadequate to demonstrate check valve position as required by Technical Specification 5.5.6 and American Society of Mechanical Engineers Code for reactor core isolation cooling condensate storage tank suction check valve 1E51-F011. Specifically, on July 12, 2004, the surveillance procedure failed to establish steady-state flow conditions at the outlet of the test piping prior to data collection necessary for the verification of check valve position. Additionally, operators used non-calibrated timing and liquid collection devices while obtaining data. The net effect of the procedural deficiencies was the collection of meaningless data. The licensee corrected the deficiency by reperforming the surveillance with appropriate controls and instrumentation prior to declaring the check valve operable and initiated corrective action to obtain and implement the use of accurate flow measuring devices during future performance of the surveillance. The primary cause of this finding was related to the cross-cutting area of Human Performance.

  This finding was greater than minor because it was directly associated with the mitigating systems cornerstone objective of mitigating system availability and operability. The inspectors concluded that with the observed test methodology and acceptance criteria, an operator could credibly conclude the check valve was shut when in fact it was open. The finding was of very low safety significance because the operator performing the July 12, 2004 surveillance determined the valve to have failed the surveillance test despite inconclusive test data. As such, reactor core isolation cooling suction remained aligned to the suppression pool and system operability was maintained. (Section 1R22)

- Green. The inspectors identified a finding of very low safety significance for the licensee's repetitive failure to identify and correct issues associated with the implementation of on-line risk management. On June 29, 2004, the inspectors identified that the licensee failed to establish the appropriate protected train postings during a planned Division 3 emergency diesel generator unavailability. This occurred on the licensee's first opportunity to implement a new internal procedure (revision dated June 22, 2004) for posting protected equipment, following the November 3, 2003, failure to post the motor feed pump as protected during a Division 1 outage. The licensee took immediate corrective action to correct the identified posting deficiency and commenced a complete walkdown of all required postings. The primary cause of this finding was related to the cross-cutting area of Problem Identification and Resolution.

  This finding was greater than minor because if left uncorrected it could evolve into a more significant safety concern. This was previously demonstrated when the motor feed pump was left unprotected in November 2003. Although not suited for Significance Determination Process review, the finding was determined to be of very low safety significance, in that in this instance, the repetitive failure to implement on-line risk management did not result in a substantive increase in on-line risk due to the short duration of the elevated risk configuration (less than three hours actual unavailability); no work was scheduled on the improperly posted equipment; no personnel were observed in the area; and it is not a likely "transit" area for personnel. The finding was not considered a violation of regulatory requirements because the licensee programs and procedures for the management of on-line risk are not 10 CFR Part 50, Appendix B programs or procedures. (Section 4OA2)

- Green. A self-revealed violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions," occurred when the Division 1 emergency service water pump failed during routine pump operation on May 21, 2004. Specifically, the licensee failed to preclude repetition of a significant condition adverse to quality in that the licensee had rebuilt the pump in September 2003 following a similar failure. During the reassembly in September 2003 the parts used had nonconformances and correction of these nonconformances introduced stress risers to the affected keyways. Combined with a marginal design for the coupling, the coupling failed on May 21, 2004. The licensee restored the pump to operable status with an enhanced coupling design on May 29, 2004. The primary cause of this finding was related to the cross-cutting area of Problem Identification and Resolution.

  The inspectors concluded after a Significance Determination Process Phase 3 evaluation of the finding that it was of very low safety significance. Since there was a loss of safety function associated with the finding, the inspectors performed a Phase 2 analysis on the finding using the site specific notebook. Based on this analysis, the inspectors forwarded the finding to the regional senior reactor analyst. The analyst evaluated the finding using the simplified plant analysis risk model and determined that the finding was of very low safety significance. (Section 4OA5)

B. Licensee-Identified Violations

Three violations of very low safety significance which were identified by the licensee have been reviewed by the inspectors. Corrective actions taken or planned 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 and remained there except for minor downpowers for weekly control rod surveillance testing until September 25, 2004, when power was reduced to 56 percent for performance of a rod sequence exchange. After ascending to 100 percent power on September 28, 2004, the plant remained at 100 percent power for the remainder of the inspection period.

1. REACTOR SAFETY

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

1REP Equipment Availability and Functional Capability (71111.EP)

.1 Operability Evaluations (OEs)

a. Inspection Scope

The inspectors selected condition reports (CRs) related to potential operability issues 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 and design criteria in the appropriate sections of the Technical Specifications (TSs) and Updated Safety Analysis Report (USAR) to the licensee's evaluations, to verify that the components or systems were operable. Where compensatory measures were required to maintain operability, the inspectors verified that the measures were in place, would work as intended, and were properly controlled. Additionally, the inspectors verified, where appropriate, compliance with bounding limitations associated with the evaluations. The inspectors reviewed the following seven OEs:

- an OE of EDG operability due to latent issue review team questions concerning fuel availability requirements completed on June 18, 2004;
- an OE of reactor water cleanup system operability following the licensee's identification of inadequate support for instrument root valves completed on June 23, 2004;
- an OE which assessed EDG operability against erroneous room temperature values in a calculation for starting air system capacity requirements completed on July 7, 2004;
- an OE associated with reactor core isolation cooling (RCIC) system operability following failure of a condensate storage tank (CST) suction path check valve during surveillance testing on July 12, 2004;

- an OE associated with design pressure of the EDG starting air system exceeding the published design pressure rating of the control air supply filters completed on July 23, 2004;
- an OE associated with fretting of EDG fuel return piping completed on August 6, 2004; and
- an OE associated with ESW pump motor torque completed on September 15, 2004.

b. Findings

.1 Inadequate Instrumentation

Introduction: A finding of very low safety significance was identified by the inspectors for a violation of 10 CFR Part 50, Appendix B, Criterion XII, for failure to verify that instrumentation used to measure diesel room temperature was calibrated with sufficient accuracy to ensure diesel generator starting air operability.

Description: On July 7, 2004, the inspectors reviewed an OE related to the EDG starting air system. The licensee had identified that initial testing performed on the starting air system was conducted at 69° F; however, the established room temperature limits were 108° F. The licensee concluded that with the elevated temperature, five EDG starts could not be assured. The licensee performed a calculation and determined that as long as room temperature remained less than 105° F, TS established pressure limits would provide five starts. However, the calculation performed by the licensee incorrectly used gage pressure vice absolute pressure resulting in a 1° F non-conservative error. The licensee implemented the corrected limit of 104° F, but failed to account for instrument error in their implementation of the limit. The instrument used to monitor EDG room temperature provides read out in 5° F increments and was calibrated to approximately +/- 5E F. Without taking these factors into account, the licensee established action to start ventilation fans when the temperature exceeded 100° F and limiting condition for operation (LCO) entry above 104° F. After the inspectors discussed instrument accuracy with the licensee, the licensee implemented a control temperature of 95° F at which point they would start EDG room ventilation. Subsequent review by the licensee concluded that the methods used for the original analysis were conservative and that an ideal gas model with only pressure-volume work occurring best represented the air start. This model resulted in air start capacity that was independent of temperature.

Analysis: The inspectors determined that the licensee’s failure to establish limits sufficient to ensure that limits in the OE were not exceeded was more than minor because it could reasonably be a precursor to a more significant event. Specifically, when implementing OEs the licensee frequently uses installed plant instrumentation. Continued reliance on instrumentation without consideration of the calibration tolerance of that instrumentation can reasonably lead to a situation where established limits are outside the bounds evaluated in the OE. The finding also affected the cross-cutting issue of Human Performance because the licensee’s staff failed to recognize that instrument accuracy must be considered when establishing operating limits.

Using IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors reviewed the finding against the Phase 1 Screening Worksheet Mitigating Systems Cornerstone. The inspectors determined the finding did not involve the loss of safety function; and therefore, concluded that the finding was of very low safety significance.

Enforcement: Appendix B, Criterion XII of 10 CFR Part 50 states, in part, that "Measures shall be established to assure that tools, gages, instruments and other measuring and testing devices used in activities affecting quality are properly controlled, calibrated, and adjusted at specified periods to maintain accuracy within necessary limits." Contrary to this requirement, on July 7, 2004, the licensee failed to take measures to ensure the device used to measure EDG room temperature had sufficient accuracy to ensure that the room remained within required temperature limits. Specifically, the licensee determined that room temperature must remain below 104° F, established limits to enter an LCO at that temperature, but measured temperature using a device with a 5° F tolerance. This created a condition whereby the room temperature could exceed the limit without the measuring device indicating that condition. Because of the very low safety significance and because the issue has been entered into the licensee's corrective action program (CR 04-03993), the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy
(NCV 05000440/2004013-01).

.2 Failure to Identify a Condition Adverse to Quality

Introduction: A finding of very low safety significance was identified by the inspectors for a violation of 10 CFR Part 50, Appendix B, Criterion XVI, for failing to detect a condition adverse to quality. Specifically, the licensee identified vibration induced wear on EDG fuel oil return lines but did not measure the depth of the worst fret and erroneously declared operability based on a less severe fret.

Description: On August 12, 2004, the inspectors reviewed an OE related to the EDG fuel oil system. The licensee had identified that over time, fretting had occurred on EDG fuel oil return lines. Even though the licensee identified several locations where frets existed, the licensee measured only one location. The inspectors reviewed the OE and performed a walkdown of the affected piping. Based on field observations of the pipe, the inspectors questioned the licensee's selection of the most severe fret. The licensee then measured the fret depth and concluded that the previous measurement was not at the worst fret. With the new information, the licensee performed vibration measurements and performed calculations on the pipe to determine available margin. This analysis concluded that minimal margin existed and that the EDG could no longer be considered operable. On August 14, 2004, the licensee replaced the fretted section of pipe and performed a successful post-maintenance test of the EDG.

The inspectors have noted that the licensee does not treat OEs with the same level of quality assurance and control as similar activities on safety-related equipment. For example, the measurements used for the initial OE were informal measurements taken by a standard machinist's rule. The information was transmitted verbally and no independent verification occurred. Further, only one location was measured which led to the licensee's failure to evaluate the worst location. For the revised OE, the licensee improved their data quality assurance by using quality control inspection reports. The inspectors have previously noted a lesser application of quality standards in OE than in routine activities. For example, in a prior OE on control room habitability, the licensee based a portion of the operability argument on performance of uncalibrated humidity control equipment.

Analysis: The inspectors determined that the licensee's failure to identify and evaluate the worst section of pipe was more than minor because it directly effected the mitigating system cornerstone objective of the reliability of a mitigating system. Specifically, the contact between the fuel pipe and bracket was slowly eroding the pipe and would eventually create a hole in the pipe thus rendering the EDG inoperable. The finding also affected the cross-cutting area of Problem Identification and Resolution because the licensee failed to identify and evaluate the worst fret location.

Using IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors reviewed the finding against the Phase 1 Screening Worksheet Mitigating Systems Cornerstone. The licensee declared the system inoperable based on analysis that concluded the pipe would eventually fail. Since the pipe had yet to fail, the inspectors concluded that there was no actual loss of safety function, the finding was of very low safety significance.

Enforcement: Appendix B, Criterion XVI of 10 CFR Part 50 states, in part, that "Measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected." Contrary to this requirement, on August 12, 2004, the NRC identified that the licensee failed to identify the worst fret location. Specifically, the licensee failed to appropriately measure the depths of identified frets and used visual estimates of the worst fret to select the one to measure. As a result, the licensee failed to identify and evaluate the worst fret and subsequent evaluation of it resulted in declaration of EDG inoperability. Because of the very low safety significance and because the issue has been entered into the licensee's corrective action program (CR-04-04176), the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy **(NCV 05000440/2004013-02)**.

.2 Operator Workarounds

a. Inspection Scope

During the week of August 23, 2004, the inspectors reviewed an operator walkaround associated with a degrading power supply for the turbine supervisory circuit. Since the failing power supply was causing erroneous and increasing vibration readings, the licensee bypassed the automatic turbine trip associated with turbine vibration. The licensee established hourly monitoring of a locally installed vibration monitor to compensate for the erroneous readings. In addition, action levels were established to notify licensee management should vibration levels increase to 10 mils.

b. Findings

No findings of significance were identified.

.3 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed temporary modifications to verify that the modification was properly installed, had no effect on the operability of the safety-related equipment, and met design basis requirements. The inspectors assessed the acceptability of the temporary modification to the facility by comparing the 10 CFR 50.59 screening evaluation and supporting operating procedures to the design basis documents and plant drawings. The inspectors also checked temporary modification tags and walked down the system to ensure the temporary modification did not impact the operability of interfacing systems. The inspectors reviewed the following three temporary modifications:

- during the week of July 5, 2004, the inspectors reviewed the temporary modification package associated with Temporary Modification 04-0003, “Temporary Modification to Isolate Pressure Relief Valve 1C11F0025B;”
- during the week of September 13, 2004, the inspectors reviewed the installation of a temporary diesel fire pump associated with a rebuild of the permanently installed motor fire pump; and
- during the week of September 13, 2004, the inspectors reviewed the installation of temporary modification to use an alternate pressure tap to monitor differential pressure across the recirculation pump seal purge filter.

b. Findings

No findings of significance were identified.

.4 Maintenance Effectiveness

a. Inspection Scope

The inspectors reviewed the licensee's implementation of the maintenance rule requirements to verify that 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, selected surveillance test procedures, and a sample of CRs to verify that 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 verify that the criteria adequately monitored equipment performance and to verify that licensee changes to performance criteria were reflected in the licensee's probabilistic risk assessment. During this inspection period the inspectors reviewed the following two areas:

- emergency closed cooling water system; and
- airborne radiation monitoring systems.

The problem identification and resolution CRs reviewed are listed in the attached List of Documents Reviewed.

b. Findings

No findings of significance were identified.

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

During the week of August 9, 2004, the inspectors observed licensee treatment of raw water systems to control populations of zebra mussels. The inspectors observed pre-job briefs and selected portions of the treatment activity. Periodically following the treatment, the inspectors observed licensee inspections of bio boxes to validate the treatment's effectiveness.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

.1 Complete System Walkdown

a. Inspection Scope

The inspectors performed a complete walkdown of accessible portions of the residual heat removal (RHR) system to verify system operability during the week of August 22, 2004. The RHR system was selected due to its risk significance and current system health status. The inspectors used RHR valve lineup instructions (VLIs) and system drawings to accomplish the inspection.

The inspectors observed selected switch and valve positions, electrical power availability, system pressure and temperature indications, component labeling, and general material condition. The inspectors also reviewed open system engineering issues as identified in the licensee's Quarterly System Health Reports, outstanding maintenance work requests, and a sampling of licensee CRs to verify that problems and issues were identified, and corrected, at an appropriate threshold. Finally, the inspectors reviewed recently completed surveillance procedures to assess equipment performance demonstrations. The documents used for the walkdown and issue review are listed in the attached List of Documents Reviewed.

b. Findings

No findings of significance were identified.

.2 Partial System Walkdowns

a. Inspection Scope

The inspectors conducted partial walkdowns of the system trains listed below to verify that the systems were correctly aligned to perform their designed safety function. The inspectors used licensee VLIs and system drawings during the walkdowns. The walkdowns 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 walkdowns are listed in the attached List of Documents Reviewed. The inspectors reviewed the following three systems:

- the RCIC system following maintenance on July 19, 2004;
- the annulus exhaust gas treatment system following maintenance on September 10, 2004; and
- the fire protection system the week of September 18, 2004, during replacement of the motor fire pump.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Walkdown of Selected Fire Zones/Areas

a. Inspection Scope

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

- Fire Zone 1AB-1c, RCIC pump room;
- Fire Zone 1AB-1g; Auxiliary Building 574' elevation corridor;

- Fire Zones 1AB-3a and b, Auxiliary Building 620' elevation;
- Fire Zone 1CC-3b; Division 3 switchgear room;
- Fire Zones 1CC-4c, d, g, and h; Unit 1 125 Volt D.C. distribution and battery rooms;
- Fire Zone Unit 1 Interbus Transformers;
- Fire Zone Unit 2 Interbus and Start-up Transformers;
- Fire Area 1DG-1a; Division 1 diesel generator room; and
- Fire Zone 1AB-1f; High Pressure Core Spray (HPCS) pump room.

Emphasis was placed on the control of transient combustibles and ignition sources, the material condition of fire protection equipment, and the material condition and operational status of fire barriers used to prevent fire damage or propagation.

The inspectors looked at fire hoses, sprinklers, and portable fire extinguishers to verify that 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 verify that they were in good physical condition. The documents listed at the end of this report were used by the inspectors during the assessment of this area.

b. Findings

No findings of significance were identified.

.2 Observation of Unannounced Fire Drill

a. Inspection Scope

The inspectors observed an unannounced drill involving a fire in the emergency service water (ESW) pump house on September 15, 2004. The drill was observed to evaluate the readiness of licensee personnel to fight fires. The inspectors considered licensee performance in donning protective clothing/turnout gear and self-contained breathing apparatus, deploying firefighting equipment and fire hoses to the scene of the fire, entering the fire area in a deliberate and controlled manner, maintaining clear and concise communications, checking for fire victims and propagation of fire and smoke into other plant areas, smoke removal operations, and the use of pre-planned fire fighting strategies in evaluating the effectiveness of the fire fighting brigade. In addition, the inspectors attended the post-drill debriefing to evaluate the licensee's ability to self-critique fire fighting performance.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

During the week of August 2, 2004, the inspectors reviewed the plant roof drain system. The system was designed to provide sufficient drainage to prevent roof collapse during probable maximum precipitation. The inspectors reviewed CRs, the Perry Nuclear Power Plant (PNPP) Individual Plant Examination External Events and the USAR to evaluate the site's current ability to meet design basis requirements. The inspectors performed walkdowns of the roofs of plant structures to determine if roof drains were free from obstructions and determine if material was present that could block a roof drain.

b. Findings

No findings of significance were identified.

1R07 Heat Sink (71111.07)

a. Inspection Scope

The inspectors observed the Division 3 EDG jacket water heat exchanger performance test conducted August 25, 2004. The inspectors reviewed the licensee preliminary test results and reviewed historical trending data to verify testing frequency was sufficient to detect degradation of the heat exchanger performance.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

On July 27, 2004, the resident inspectors observed 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.

The inspectors also observed the licensee’s evaluation of crew performance to verify that the training staff had observed important performance deficiencies and specified appropriate remedial actions.

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 verify that scheduled and emergent work activities were adequately managed. In particular, the inspectors reviewed the licensee's program for conducting maintenance risk assessments to verify that 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 verify that the actions were accomplished when on-line risk was increased due to maintenance on risk-significant structures, systems, and components. The following seven assessments and/or activities were reviewed:

- the maintenance risk assessment for the week of June 29, 2004, which included planned Division 3 EDG inoperability for testable rupture disk testing;
- the maintenance risk assessment for the week of July 5, 2004, which included a planned outage of an offsite 345 kV line and emergent 15 kV breaker issues;
- the emergent maintenance risk assessment associated with unplanned RCIC inoperability due to failed surveillance testing the week of July 12, 2004;
- the maintenance risk assessment for the week of July 19, 2004, which included a planned inoperability of the Division 2 EDG for testable rupture disk testing;
- the maintenance risk assessment for the week of August 9, 2004, which included EDG inoperability during fuel oil piping replacement;
- the maintenance risk assessment for the week of September 6, 2004, which included planned inoperability of the Division 1 EDG for testable rupture disk testing, unplanned unavailability of the RHR 'A' train due to issues with room cooler fasteners, and the addition of work activities resulting from licensee initiatives with respect to maintenance backlog reduction; and
- the maintenance risk assessment for the week of September 13, 2004, which included planned inoperability of the motor driven fire pump which involved a quality assurance stop work order due to vendor oversight issues.

b. Findings

A finding involving the June 29, 2004 planned Division 3 EDG inoperability is discussed in Section 4OA2.2. No additional findings of significance were identified.

1R14 Operator Performance During Non-Routine Evolutions and Events (71111.14)

.1 Restoration of Turbine Supervisory Indication

a. On September 1, 2004, the inspectors observed the licensee's restoration of the turbine supervisory instrumentation following power supply replacement. Restoration of the turbine supervisory instrumentation represented a risk of an erroneous turbine trip and subsequent scram from a voltage transient. The inspectors observed the pre-job brief to verify operators were aware of the risks and actions to take if a turbine trip occurred. The inspectors observed the coordination between the reactor operator and the switch operator to verify if station expectations were met.

b. Findings

No findings of significance were identified.

.2 Hot Work on Auxiliary Transformer Relay

a. On September 3, 2004, the inspectors observed the licensee's actions to correct a hot terminal connection on a Unit 1 auxiliary transformer relay. The connection affected the differential relay which provides an automatic trip of the auxiliary transformer. Should this transformer trip, the turbine would trip and the reactor would scram. The inspectors observed briefings of the operating crew and discussions of contingencies should the reactor scram while performing the work. The inspectors observed the technicians' actions to prevent inadvertent actuation of the trip circuit and coordination with the shift manager prior to performing the more risk-significant steps of the evolution.

b. Findings

No findings of significance were identified.

.3 Power Reduction for Rod Line Change

a. Inspection Scope

During the week of September 20, 2004, the inspectors observed portions of the licensee's planned power reduction and sequence exchange. The inspectors observed the licensee's testing of various control rods for channel bow and scram-time testing. The inspectors observed licensee response to control room alarms. Due to the number of control rods made inoperable for either planned maintenance or defect suppression, the inspectors paid particular attention to the licensee's adherence to LCO requirements for inoperable control rods.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors evaluated the following post-maintenance testing (PMT) activities for risk-significant systems to assess 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 TSs, the USAR, 10 CFR Part 50 requirements, licensee procedures, and various NRC generic communications. In addition, the inspectors reviewed CRs associated with PMT to determine if 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 six post-maintenance activities were reviewed:

- testing of the off-gas vent pipe radiation monitor following replacement of a potentiometer on July 22, 2004;
- testing of breaker L2006 following replacement on August 3, 2004;
- testing of the control complex chilled water (CCCW) system 'A' chiller breaker auxiliary switch following adjustment on August 13, 2004;
- testing of scram discharge volume solenoids following replacement on August 19, 2004;
- testing of the Division 3 preferred source breaker EH1303 following planned servicing on September 20 and 22, 2004; and
- testing of the HPCS test return valve following preventive maintenance on September 20, 2004.

b. Findings

Introduction: A finding of very low safety significance was identified by the inspectors for a violation of 10 CFR Part 50, Appendix B, Criterion XVI, for the licensee's failure to identify a condition adverse to quality. Specifically, non-licensed operators (NLOs) failed to identify that the auxiliary switch in the CCCW system 'A' chiller breaker cubicle was misaligned.

Description: On August 13, 2004, the inspectors observed NLOs performing electrical breaker operations while restoring the CCCW 'A' chiller to service following maintenance activities. The inspectors observed that the NLOs were using the appropriate procedure and that, per procedure, the alignment of the breaker's cell switch contacts were verified to be correctly aligned. While the breaker cubicle was open, the inspectors observed that the breaker's auxiliary switch appeared to be out of alignment. When the NLOs completed their activities, the inspectors asked if the alignment of the auxiliary switch was adequate. The NLOs noted that verification of the auxiliary switch was not required by procedure, but after examining the auxiliary switch, contacted the control room for assistance. Subsequent review by maintenance and engineering confirmed the inspectors' observations that the switch was in need of alignment. A work package was initiated and the auxiliary switch was aligned later that same day.

The inspectors observed the auxiliary switch alignment and subsequent PMT. Testing activities required the licensee to close the breaker in the test position to verify proper switch alignment in both the open and closed positions. The inspectors observed that upon closing the breaker, the breaker immediately reopened. Subsequent review by the licensee identified that close permissives were not satisfied with the system configuration in place at that time, thus the breaker re-opening was the appropriate system response. The inspectors were concerned that the licensee did not understand expected system response prior to operating equipment. The inspectors were equally concerned that a CR was not initiated to document the issue until the inspectors discussed the issue with licensee management at a later date. Although the system response was, after review, determined to be proper, the licensee accumulated additional safety system unavailability time (the CCCW 'A' chiller remained out of service) while the issue was reviewed, an appropriate path forward developed, and the testing re-performed. After discussion with plant management, the issue was entered into the licensee’s corrective action program as CR 04-04485.

<u>Analysis</u>: The inspectors determined that the licensee’s failure to identify the auxiliary switch misalignment, a condition adverse to quality, was more than minor because it could reasonably be a precursor to a more significant event. In fact, the issue was similar to the failure to properly align the HPCS system pump breaker cell switch which resulted in the failure of the pump to start during surveillance testing **(VIO 05000440/2002008-02)**. The primary cause of this finding was related to the cross-cutting area of Problem Identification and Resolution in that the NLOs did not identify the auxiliary switch misalignment.

Using IMC 0609, Appendix A, “Significance Determination of Reactor Inspection Findings for At-Power Situations,” the inspectors reviewed the finding against the Phase 1 Screening Worksheet Mitigating Systems Cornerstone. The inspectors determined the finding did not involve the loss of safety function; and therefore, concluded that the finding was of very low safety significance.

<u>Enforcement</u>: Appendix B of 10 CFR Part 50, Criterion XVI, “Corrective Actions,” requires, in part, that measures be established to assure that conditions adverse to quality are promptly identified and corrected. Contrary to this requirement, on August 13, 2004, measures were not established to ensure that NLOs would identify and correct a misaligned auxiliary switch in safety-related breaker cubicles. Because of the very low safety significance and because the issue has been entered into the licensee’s corrective action program (CR 04-04197), the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy **(NCV 05000440/2004013-03)**.

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 TSs; 10 CFR Part 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 reviewed whether test control was properly coordinated with the control room and performed in the sequence specified in the surveillance instruction (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 seven surveillance activities assessed were:

- testing of the HPCS EDG fuel oil transfer system on July 1, 2004;
- testing of the containment vacuum breaker differential pressure actuation circuitry conducted July 6, 2004;
- RCIC pump and valve testing commenced on July 12, 2004, and completed on July 16, 2004;
- testing of suppression pool level instrumentation on July 29, 2004;
- local leak rate testing of containment and drywell purge valves on August 3, 2004;
- calibration of main steam line high flow on August 30, 2004; and
- HPCS pump and valve testing conducted September 23, 2004.

b. Findings

Introduction: The inspectors identified a finding of very low safety significance for a violation of 10 CFR Part 50, Appendix B, Criterion XI. The inspectors determined that the combination of licensee testing protocol and established acceptance criteria was inadequate to demonstrate check valve position as required by TS 5.5.6 and American Society of Mechanical Engineers (ASME) code for RCIC CST suction check valve 1E51-F011.

Description: On July 12, 2004, the inspectors observed licensee performance of SVI-E51-T2001, “RCIC Pump and Valve Operability Test,” Rev. 17. One of the many functions of the test was to satisfy TS 5.5.6 requirements of exercising open and closed check valve 1E51-F011. The check valve is in the CST suction line to the RCIC pump and serves to minimize the possibility of flow of suppression pool water to the CST. The test verified the valve was closed by isolating the CST with the CST RCIC suction isolation valve, then directing leakage through a hose to a 5-gallon bucket.

The inspectors observed the evolution and noted substantial flow through the hose to the bucket. The inspectors' initial assessment was that flow was at or near the maximum achievable through the hose. The inspectors further noted that although the operator performed the testing as written, the flow-timing was conducted with a wrist watch observed by the individual operating the valve, that full flow was not established prior to beginning timing of the evolution, and that the volume of water in the bucket was never actually measured. The licensee's acceptance criteria for verifying check valve closure was observed flow of less than 15 gpm. The operator noted that he had almost filled the 5-gallon janitorial grade bucket in about 20 seconds; and therefore, concluded the acceptance criteria had not been met. The inspectors noted that another operator in the same position could easily have determined that since the presumably 5-gallon bucket was in fact less than full, the acceptance criteria was met and the check valve was closed.

Once the operator reported the failed surveillance, the shift manager declared the check valve inoperable, left RCIC aligned to the suppression pool, generated a CR, and requested an operability determination concerning RCIC system operability given the check valve test failure. With RCIC aligned to the suppression pool, the inspectors had no immediate safety concern.

Despite the clear request to provide an operability determination of RCIC system operability, the licensee's engineering staff issued an operability determination erroneously accepted by a shift manager which was simply an argument for check valve operability, not an assessment of RCIC operability as had been requested. The inappropriate use of an operability evaluation for a component which had been declared inoperable due to failed TS 5.5.6 testing was entered into the licensee's corrective action program as CR 04-03642. The inspectors noted that **NCV 05000440/2002008-01** previously identified that use of an operability determination to negate failed surveillances was inappropriate. After prolonged discussion with operations management, the licensee's engineering staff performed the requested evaluation which determined that if 1E51-F011 check valve was unable to travel to the closed position, RCIC suction needed to remain aligned to the suppression pool in order to maintain RCIC operability.

The licensee's engineering staff's position on check valve operability was based on two data points. As part of the initial investigation into the valve status, the licensee conducted additional testing which the inspectors were told established more accurate test results through establishment of steady-state flow conditions. Based on the additional testing, the licensee concluded that flow through the valve was actually 12.4 gpm which was significantly less than the 17.23 gpm maximum value. Noting that the revised testing established a steady-state constant flow, the inspectors determined the check valve could be considered to be shut with considerable leakage. The inspectors were concerned, however, that the licensee's engineering staff continued to credit the surveillance test data as additional evidence of satisfactory valve performance. When declaring the check valve operable, the unit supervisor, a senior reactor operator, documented "1E51F0011 declared operable with respect to TS 5.5.6. This is based on the Pump/Valve Record of Corrective Action which documents that the as-found leakage was less than the calculated (Calculation E51-022, Rev. 1) limit 17.23 gpm and the as-left leakage is less than the SVI limit of 15 gpm." The inspectors confirmed the as-found leakage was the 15 gpm recorded on July 12, 2004, and the as-left was the 12.4 gpm obtained during the subsequent steady-state testing.

The inspectors had several issues with the standard testing methodology and acceptance criteria and concluded that based on the July 12, 2004 test data, the position of the valve was at best indeterminate. Most notable, was the observation that although not stated explicitly in the calculation nor incorporated in the surveillance procedure, the 17.23 gpm value was clearly dependent on steady-state flow conditions. Specifically, the vent valve would need to be full open for the calculation to be valid. A smaller orifice, as one would observe as the valve is being opened or shut, would substantially alter maximum achievable flow.

With respect to the July 12, 2004, test, given the uncertainty in both measured parameters (time and volume) and the failure to establish constant flow, the inspectors concluded the licensee failed to demonstrate the check valve was in the closed position. By making modest assumptions concerning timing uncertainty, approximated to be 1 second, and valve travel, approximated to be 1 to 2 seconds in each direction, the inspectors could credibly postulate that the observed flow was indistinguishable from maximum achievable flow, and as such, the check valve could be in any position from full open to full closed.

The inspectors reviewed past E51-F011 check valve testing data. The inspectors noted the valve has historically exhibited excessive leakage which led to valve replacement in 2002. After replacement of the valve, a relatively steadily increasing trend of seat leakage was again observed. Prior to the test on July 12, 2004, leakage as high as 11 gpm had been recorded. Prior to the 2002 valve replacement, leakage as high as 13 gpm had been recorded. The inspectors noted that in April 2001, when 13 gpm was recorded, the licensee revised the acceptance criteria from 12 gpm to 15 gpm. At the time, the calculation of record identified 16.44 gpm as the maximum achievable flow. Thus, a margin of 1.44 gpm between acceptance criteria and maximum achievable was established. The maximum achievable flow was subsequently recalculated to be 17.23 gpm in July 2001.

In summary, the inspectors concluded the July 12, 2004 surveillance procedure performance failed to establish steady-state flow conditions at the outlet of the test piping prior to data collection necessary for the verification of check valve position. Additionally, operators used non-calibrated timing and liquid collection devices while obtaining data. The net effect of the procedural deficiencies was the collection of meaningless data.

<u>Analysis</u>: The inspectors determined that the licensee’s failure to specify adequate testing protocol and acceptance criteria was a performance deficiency warranting a significance determination. The inspectors determined the issue was more than minor because it was directly associated with the mitigating system cornerstone objective of mitigating system availability and operability. Specifically, operability of the RCIC system could only be assured if the system were aligned to the suppression pool should the CST suction check valve fail to close. The testing methodology combined with established acceptance criteria were inadequate to reliably determine check valve

position. The primary cause of this finding was related to the cross-cutting area of Human Performance in that performance of the surveillance test failed to collect meaningful data.

Using IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors reviewed the finding against the Phase 1 Screening Worksheet. Since the licensee subsequently established the check valve, although leaking excessively, was in the closed position, the inspectors determined that no actual loss of the RCIC safety function occurred or would have occurred had the operator determined the valve to have initially met the 15 gpm leakage.

Enforcement: Appendix B, Criterion XI of 10 CFR Part 50 states in part, that test procedures shall include provisions for assuring that all prerequisites for the given test have been met, that adequate test instrumentation is available and used, and that the test is performed under suitable environmental conditions. Contrary to these requirements, on July 12, 2004, the licensee failed to include instructions for establishing steady-state flow when testing the RCIC CST suction check valve. Additionally, the test instrumentation used, wrist watch and bucket, were considered by the inspectors to be inappropriate when attempting to distinguish 15 gpm from 17 gpm during a 20 second evolution. Because of the very low safety significance and because the issue has been entered into the licensee's corrective action program (CR 04-03576), the issue is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy **(NCV 05000440/2004013-04)**.

1EP6 Drill Evaluation (71114.06)

.1 Simulator Based Training Evolution

a. Inspection Scope

The inspectors observed the simulator control room during licensed operator continuing training on July 13, 2004. The session had been identified as contributing to the performance indicator (PI) for drill/exercise performance. The inspection focused on the ability of the licensee to appropriately classify emergency conditions and complete timely notifications in accordance with approved procedures.

b. Findings

No findings of significance were identified.

.2 Site Emergency Preparedness Drill - September 15, 2004

a. Inspection Scope

The inspectors observed the simulator control room, technical support center, and operation support center during an emergency preparedness drill conducted on

September 15, 2004. The inspection focused on the ability of the licensee to appropriately classify emergency conditions, complete timely notifications, and implement appropriate protective action recommendations in accordance with approved procedures.

b. Findings

No findings of significance were identified.

.3 Site Emergency Preparedness Drill - September 27, 2004

a. Inspection Scope

The inspectors observed the simulator control room, technical support center, and operation support center during an emergency preparedness drill conducted on September 27, 2004. The inspection focused on the ability of the licensee to appropriately implement lessons learned from the September 15, 2004 drill. The inspectors observed the licensee's classification of emergency conditions, notifications of emergency conditions, and implementation of appropriate protective action recommendations in accordance with approved procedures. The inspectors also observed interfacility communication of action prioritization.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS3 Radiation Monitoring Instrumentation and Protective Equipment (71121.03)

.1 Inspection Planning

a. Inspection Scope

The inspectors reviewed the plant Updated Final Safety Analysis Report to identify applicable radiation monitors associated with transient high and very high radiation areas including those used in remote emergency assessment. This included area radiation monitors associated with in-core instrumentation, transverse in-core probes, radwaste resin polyethylene liner fill and cask loading areas. Emergency assessment instrumentation included the high-range containment radiation monitor and the post-accident sampling system. These reviews represented one sample.

b. Findings

No findings of significance were identified.

.2 Identification of Additional Radiation Monitoring Instrumentation

a. Inspection Scope

The inspectors also identified various types of portable radiation detection instrumentation used for job coverage of high radiation area work, and other temporary area radiation monitors currently used in the plant, including continuous air monitors associated with jobs with the potential for workers to receive 50 millirem committed effective dose equivalent. The whole body counter and radiation detection instruments utilized for personnel survey and release from the radiologically controlled area and the protected area were identified. These reviews represented one sample.

b. Findings

No findings of significance were identified.

.3 Verification of Calibration, Operability, and Alarm Setpoints of Instruments and Equipment

Licensee personnel were observed performing source checks of selected instruments. The inspectors verified current calibration records, operability, and applicable alarm set points of selected instruments including accident range radiation monitors, portable hand-held survey instruments, and personnel monitoring devices. This included an evaluation of operating parameters for instrumentation used for the release of personnel and material from the radiologically restricted area to verify that detection limits were based on adequate count times and low radiological backgrounds so that the typical instrument sensitivities were achieved. Instrumentation reviewed included, but was not limited to, the following:

- PY-SVI-D17-T0374; Drywell Atmospheric Gaseous and Particulate Radiation Monitor System;
- PTI-D17-P1670; Drywell Atmosphere Radiation Monitor;
- PTI-D17-P1680; Containment Atmosphere Radiation Monitor;
- Gamma 60 Monitor;
- Eberline PCM1B;
- AMP 100;
- Canberra Fastscan Whole Body Counter;
- Bicron Analyst;
- Gilian Lapel Air Sampler;
- SAM-9 Tool Monitor;
- AMS-4 Continuous Air Monitor;
- Eberline ASP-1 REM Ball;
- Eberline Teletector; and
- Electronic Dosimeters.

The inspectors reviewed what actions would be taken when, during calibration or source checks, an instrument was found out of calibration by more than 50 percent. Should that occur, the inspectors verified that the licensee's actions would include a determination of the instrument's previous usages and the possible consequences of that use since the last calibration. The inspectors also reviewed the licensee's 10 CFR Part 61 source term analyses to determine if the calibration sources used were representative of the plant source term and that hard to detect nuclides were scaled into whole body count dose determinations. These reviews represented one sample.

b. Findings

No findings of significance were identified.

.4 Problem Identification and Resolution for Radiation Monitoring Instrumentation and Protective Equipment

a. Inspection Scope

The inspectors reviewed licensee self-assessments, audits, CRs, and special reports that involved personnel contamination monitor alarms resulting from radioactive material uptakes which produced internal exposures. This was done in order to verify that identified problems were entered into the corrective action program for resolution. Internal exposure occurrences greater than 50 millirem committed effective dose equivalent were reviewed to determine if the affected personnel were properly monitored utilizing calibrated equipment, if the data was adequately analyzed, and if internal exposures were properly assessed in accordance with licensee procedures. Licensee audit and assessment data were also evaluated to verify that deficiencies and problems with radiation protection instrumentation were identified, characterized, prioritized, and resolved using the corrective action program. These reviews represented one sample.

The inspectors reviewed corrective action program reports related to exposure significant radiological incidents that involved radiation monitoring instrument deficiencies that had occurred since the last inspection of this area. Staff members were interviewed and corrective action documents were reviewed to verify that 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 sample.

The inspectors verified that the licensee's self-assessment process identified and addressed repetitive deficiencies or significant individual deficiencies that were identified in problem identification and resolution. These reviews represented one sample.

b. <u>Findings</u>

No findings of significance were identified.

.5 <u>Radiation Protection Technician Instrument Use</u>

a. <u>Inspection Scope</u>

The inspectors verified that instrument calibrations had not lapsed, reviewed source response check data records for radiation detection instruments staged for use, and observed radiation protection technicians for appropriate instrument selection and self-verification of instrument operability prior to use. These reviews represented one sample.

b. <u>Findings</u>

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 <u>Performance Indicator Verification</u> (71151)

a. <u>Inspection Scope</u>

The inspectors reviewed reported second quarter 2004 data for HPCS and RHR system unavailability PIs using the definitions and guidance contained in Nuclear Energy Institute (NEI) 99-02, "Regulatory Assessment Indicator Guideline," Revision 2. The inspectors reviewed station logs, event notification reports, licensee event reports (LERs), CRs, and TS logs to verify the accuracy of the licensee's data submission.

b. <u>Findings</u>

During review of the PI for safety system unavailability for RHR, the inspectors noted that the licensee did not include unavailable hours for RHR 'B' while the plant was shutdown for ESW pump repairs. During this shutdown, the licensee appropriately counted unavailability hours for RHR 'A.' However, prior to removing ESW 'B' from service, which renders RHR 'B' inoperable and unavailable, the licensee established an off-normal instruction (ONI) that would provide decay heat removal (DHR) provided reactor water temperature remained below 150E F. This method used a feed and bleed strategy that used reactor water cleanup, condensate and feed systems to use the main condenser as the heat sink. The NEI guidance allows exclusion of RHR unavailability hours only if an NRC-approved alternate method of DHR was available. Since the NRC has neither reviewed nor approved this method as an alternate DHR path, the inspectors concluded these hours should be included, which would result in a white PI for RHR system unavailability. The licensee contends that any method permitted by TSs was NRC-approved; and therefore, exclusion of these hours is consistent with NEI guidance. Perry TSs do not list acceptable alternate methods of alternate DHR; however, the basis does state that the cooling capacity of the alternate method must be demonstrated empirically or by calculation. Further, the basis states that alternate methods include, but are not limited to, reactor water cleanup. The licensee determined the capacity of the feed and bleed method by calculation. The licensee has submitted a "Frequently Asked Question" (FAQ) on this issue. This is an unresolved item **(URI-05000440/2004013-05)** pending resolution of the FAQ.

Cornerstones: Barrier Integrity, Occupational and Public Radiation Safety

.1 Reactor Safety Strategic Area

a. Inspection Scope

The inspectors sampled the licensee's submittals for PIs and periods listed below. The inspectors used PI definitions and guidance contained in Revision 2 of NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," to verify the accuracy of the PI data. The following PI was reviewed:

- Reactor Coolant System Specific Activity for Unit 1

  The inspectors reviewed Chemistry Department records and selected isotopic analyses (August 2003 through August 2004) to verify that the greatest Dose Equivalent Iodine (DEI) values obtained during those months corresponded with the values reported to the NRC. The inspectors also reviewed selected DEI calculations to verify that the appropriate conversion factors were used in the assessment as required by TSs. Additionally, the inspectors observed a chemistry technician obtain and analyze a reactor coolant sample for DEI to verify adherence with licensee procedures for the collection and analysis of reactor coolant system samples.

b. Findings

No findings of significance were identified.

.2 Radiation Safety Strategic Area

a. Inspection Scope

The inspectors sampled the licensee's submittals for PIs and periods listed below. The inspectors used PI definitions and guidance contained in Revision 2 of NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," to verify the accuracy of the PI data. The following PIs were reviewed:

- Occupational Exposure Control Effectiveness for Unit 1

  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 conducted walkdowns of accessible locked high radiation area entrances to verify the adequacy of controls in place for these areas. Data collection and analyses methods for PIs were discussed with licensee representatives to verify that there were no unaccounted for occurrences in the Occupational Radiation Safety PI as defined in Revision 2 of NEI 99-02, "Regulatory Assessment Performance Indicator Guideline."

- Radiological Environmental TS/Offsite Dose Calculation Manual (RETS/ODCM) Radiological Effluent Occurrences for Unit 1

  The inspectors reviewed data associated with the RETS/ODCM PI to determine if the indicator was accurately assessed and reported. This review included the licensee's CR database and selected CRs generated over the previous four quarters, to identify any potential occurrences such as unmonitored, uncontrolled or improperly calculated effluent releases that may have impacted offsite dose. The inspectors also selectively reviewed gaseous and liquid effluent release data and the results of associated offsite dose calculations and quarterly PI verification records generated over the previous four quarters. Data collection and analyses methods for PIs were discussed with licensee representatives to determine if the process was implemented consistent with industry guidance in Revision 2 of NEI 99-02, "Regulatory Assessment Performance Indicator Guideline."

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 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 verify that 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.

b. Findings

No findings of significance were identified.

.2 Annual Sample Review - On-Line Risk Management

Introduction

In previous months, the inspectors have identified several issues in the area of on-line risk management. As discussed in NRC Integrated Inspection Report 05000440/2003010, the inspectors have identified issues such as site-wide communications identifying the incorrect division as protected, the omission of risk-significant systems, and unnecessary entries into elevated risk configurations. As discussed in that inspection report, the inspectors determined the majority of the issues to be of minor significance, but did identify an NCV **(NCV-05000440/2003010-01)** of 10 CFR 50.65(a)(4) for the licensee's failure to manage risk during a Division 1 outage on November 3, 2003. Specifically, the licensee failed to communicate that the motor feed pump (MFP) was to be protected as required by their on-line risk management strategy. As a result, the MFP was not posted as protected equipment in accordance with site policies and procedures, nor more significantly, was control room supervision aware that the MFP required such protection. The licensee's failure to properly manage on-line risk was entered into their corrective action program as CR 03-06022.

On June 29, 2004, the inspectors reviewed the implementation of the licensee's on-line risk management during a planned 7-hour Division 3 EDG unavailability. During the review, the inspectors identified that the licensee again failed to implement the measures identified in site procedures. Specifically, the inspectors observed that the Division 1 and Division 2 battery rooms were not posted as protected equipment. The licensee entered the posting error into their corrective action program as CR 04-03361.

The inspectors selected CR 03-06022 and CR 04-03361 for an annual sample review (one sample) of the licensee's problem identification and resolution program. The inspectors reviewed two key aspects of the licensee's problem identification and resolution program; the licensee's ability to identify problems; and the ability, once identified, to correct problems. With respect to on-line risk management, the inspectors determined weaknesses existed in both areas.

a. Effectiveness of Problem Identification

(1) Inspection Scope

The inspectors reviewed the licensee's corrective action database for issues concerning on-line risk management problems to verify that the licensee's identification of problems was complete, timely, and accurate.

(2) Issues

With respect to the protection of risk-significant equipment during entries into elevated risk configurations, the inspectors were only able to locate inspector-identified issues in the licensee's corrective action program. Additionally, the inspectors noted that several minor issues identified by the inspectors had not been entered into the licensee's corrective program.

While discussing protected train measures with licensee management, the inspectors were repeatedly informed of licensee management's expectation that protected equipment postings be walked down by a licensee manager. The inspectors noted that this expectation was not included in the licensee's governing document PYBP-POS-2-2, "Protected Equipment Postings," Rev. 3. The inspectors were concerned about the licensee's implementation of the expectation in that there were no documented instances of the walkdowns identifying any issues. While it was possible the walkdowns were identifying and correcting problems on the spot, such actions would represent missed opportunities to determine the cause of the error, extent of condition, and any additional corrective action.

The inspectors' concerns about licensee problem identification are best exemplified by the events of June 29, 2004. The licensee's work implementation schedule identified a 7-hour period of Division 3 EDG unavailability for work associated with a testable rupture disk. As such, the licensee intended to implement the protected train strategy identified in PYBP-POS-2-2. With work scheduled to commence at approximately 8:00 a.m., the mid-shift shift manager released the protected equipment posting checklist for the evolution at approximately 11:30 p.m. on June 28, 2004. Due to a shortage of signs, completion of the checklist was turned over to the day-shift operations crew. Additional signs were posted at approximately 8:00 a.m. and the work was released shortly thereafter. The inspectors walked down the postings at approximately 10:00 a.m. and promptly identified deficiencies in that neither the Division 1 nor Division 2 battery rooms were posted as protected. After identifying the condition to the control room, the areas were promptly posted and complete verification of postings was initiated by the unit supervisor. Subsequent review by the inspectors identified that the independent management walkdown of the postings had yet to be accomplished - 2 hours into an identified 7-hour evolution.

The inspectors concluded the licensee's problem identification and resolution program was not effective in identifying problems associated with the posting/protection of risk-significant equipment during periods of elevated on-line risk. This performance deficiency is included in the subsequent discussion of effectiveness of corrective actions.

b. Effectiveness of Corrective Actions

(1) Inspection Scope

The inspectors reviewed the corrective actions identified in CR 03-06022 with respect to the as-found condition documented in CR 04-03361.

(2) Findings

Introduction: The inspectors identified a finding in the cross-cutting area of Problem Identification and Resolution associated with the licensee's repetitive failure to identify and correct issues associated with the implementation of on-line risk management. The finding was not considered a violation of regulatory requirements because the licensee programs and procedures for the management of on-line risk are not 10 CFR Part 50, Appendix B programs or procedures.

Description: On June 29, 2004, the inspectors identified that the licensee failed to establish the appropriate protected train postings during planned Division 3 EDG unavailability as discussed above. Given the apparent similarities to a previous inspector-identified issue **(NCV-05000440/2003010-01)** the inspectors reviewed previous corrective actions to assess effectiveness. Following the November 3, 2003, issue with the protection of the MFP, the licensee initiated action to establish lists of protected systems, trains, and components for likely elevated plant risk configurations such as a Division 3 EDG outage. The inspectors noted that 15 such lists were established and incorporated into licensee operations section business practice PYBP-POS-2-2. The lists identified systems and trains and specified postings of areas or, when possible, specific access points for posting. For example, during a Division 3 EDG outage, the document specified R42, ED-1-A Bus, CC 638', doors CC-408 and CC-412 for the Unit 1 Division 1 Battery and Equipment Rooms. The licensee's process then requires that the information contained on the attachment tables be transcribed onto a protected equipment posting checklist. When the checklist was developed on June 28, 2004, for the June 29, 2004, Division 3 EDG unavailability, considerably less detail was used. For example, the guidance for the R42, ED-1-A Bus was simply "ED1A bus area, CC-638." With that guidance, the NLO performing the checklist only posted the bus room and not the associated battery room. The inspectors concluded that the licensee's corrective actions inserted a new opportunity for failure in that it required transcription of posting locations from one document to another. The relatively new procedure revision, effective June 22, 2004, combined with the demonstrated lack of independent management oversight, resulted in failed implementation of the licensee's on-line risk management program on June 29, 2004.

Analysis: The inspectors determined that the licensee's repetitive failure to identify and correct issues associated with the implementation of on-line risk management was a performance deficiency. The inspectors determined the issue was more than minor because such failures had led to more significant safety concerns, such as the failure to protect the MFP, and that if left uncorrected was likely to continue to do so. The finding clearly affected the cross-cutting issue of Problem Identification and Resolution because of the repetitive nature of the issue.

Although not suited for SDP review, the finding was determined to be of very low safety significance in that in this instance the repetitive failure to implement on-line risk management did not result in a substantive increase in on-line risk due to the short duration of the elevated risk configuration (less than 3 hours actual unavailability), the fact that no work was scheduled on the improperly posted equipment, the fact that no personnel were observed in the area, and the fact that it is not a likely "transit" area for personnel.

Enforcement: The finding was not considered a violation of regulatory requirements because the licensee programs and procedures for the management of on-line risk are not 10 CFR Part 50, Appendix B programs or procedures. This issue was considered to be a finding of very low safety significance **(FIN-05000440/2004013-06)**. The ineffective corrective action implemented through CR 03-06022 was addressed as part of CR 04-03361 investigation with appropriate corrective action planned.

4OA3 Event Followup (71153)

.1 Alert Due to Indicated Off-Gas System High Gas Radiation Levels

a. Inspection Scope

The inspectors observed control room personnel responding to an off-scale high radiation alarm for the off-gas system vent pipe. The inspectors arrived to observe licensee actions to validate the alarm including troubleshooting activities, monitoring of plant conditions and completion of ONI actions. The inspectors reviewed the licensee's emergency plan to verify that the licensee appropriately characterized the event as an Alert and that notification of county, state, and federal agencies occurred in a timely manner.

At 3:44 a.m. on July 20, 2004, the PNPP declared an Alert when the gas channel of the off-gas building vent pipe indicated high off-scale. Complimentary channels measuring iodine and particulate did not indicate a change in radioactive constituents. The licensee took grab samples of the off-gas vent that did not identify any radioactive release. At 9:01 a.m., after confirming that no release had occurred and that the site no longer met the criteria for an Alert, the licensee exited the Alert condition.

b. Findings

During the event, the inspectors noted that the licensee failed to perform an emergency dose assessment using the Computer-Assisted Dose Assessment Program (CADAP) within 15 minutes as required by their emergency plan. In part, this assessment was required to verify that the licensee did not cross a threshold from an Alert to a Site Area Emergency. While this assessment did not occur until 1 hour and 45 minutes after declaration of the Alert, aside from the off-gas building vent pipe radiation monitor, no other indications of a release existed. The CADAP program used automated data inputs coupled with manual data entry to calculate dose at the site boundaries. One of the inputs to the program was the Post-Accident Radiation Monitor for the off-gas building. During the event, the inspectors observed this monitor and it read at or near the bottom of the scale. The inspectors reviewed the licensee's implementing procedures in effect during the Alert and concluded that the procedures did not provide instruction that would ensure the 15-minute time requirement would be met.

Since the Alert, the licensee has established measures to ensure that grab sampling and CADAP analysis can be completed within 15 minutes. The licensee has validated its ability to meet the 15-minute requirement and maintains additional staff to perform these actions. Based on these actions, the inspectors concluded that further review by an emergency preparedness specialist could occur at a later date. Pending review by an emergency preparedness specialist to determine the nature of any associated performance deficiency as well as the safety significance, this issue was considered to be an unresolved item (**URI-05000440/2004013-07)**.

.2 Retraction of Event Notification Concerning Exceeding Licensed Power Level

On June16, 2004, the licensee reported they had exceeded licensed power level due to improper replacement of a feedwater resistence temperature detector. On August 17, 2004, the licensee retracted the event notification based on a re-evaluation of reactor power using as-found calibration data and a new methodology for determining the resulting error in calculated reactor power. The inspectors reviewed the licensee's basis for retracting the event notification. No new findings were identified.

.3 (Closed) LER 05000440/2003-005-01: Technical Specification Violation/Loss of Safety Function Due to Air Bound Waterleg Pump.

As documented in NRC Inspection Report 05000440/2004007, the licensee's revised root cause evaluation more clearly delineated inadequate site venting procedures as a root cause as opposed to a contributing cause. This revision was submitted to reflect the revised root cause. The NRC's final determination, which specifically addressed inadequate venting procedures, was that the pump failure was an issue of low to moderate safety significance (White) (**VIO 05000440/2004006-01**). This LER is closed.

.4 <u>(Closed) LER 05000440/2004-001-00 and 01</u>: Emergency Service Water Pump Failure.

As documented in NRC Inspection Report 05000440/2004011, the licensee experienced a failure of the 'A' ESW pump. Revision 0 of the LER identified the technical causes of failure, summarized the risk significance of the failure and the corrective actions for the pump failure. The licensee has replaced the failed coupling with a new design to preclude failure of the pump's coupling. Revision 1 of the LER included a 10 CFR Part 21 notification on the failed coupling and added to the root cause that management and organization issues contributed to the repeat failure of the pump. The NRC's final significance determination, included in this report, was that the pump failure was an issue of very low safety significance (Green) (**NCV 05000440/2004011-02**). No new findings were identified. This LER is closed.

4OA4 <u>Cross-Cutting Aspects of Findings</u>

.1 A finding described in Section 1REP.1 of this report had, as its primary cause, a human performance deficiency in that the licensee failed to recognize that instrument accuracy must be considered when establishing operating limits. As a result, the licensee failed to take measures to ensure the device used to measure EDG room temperature had sufficient accuracy to ensure that the room remained within required temperature limits.

.2 A finding described in Section 1REP.1 of this report had, as its primary cause, a problem identification and resolution deficiency in that the licensee failed to detect a condition adverse to quality. Specifically, the licensee identified fretting on EDG fuel oil return lines but did not measure the depth of the worst fret and erroneously declared operability based on a less severe fret.

.3 A finding described in Section 1R19 of this report had, as its primary cause, a problem identification and resolution deficiency in that the licensee failed to detect a condition adverse to quality. Specifically, the licensee failed to identify a misaligned auxiliary switch in a safety-related breaker cubicle.

.4 A finding described in Section 1R22 of this report had, as its primary cause, a human performance deficiency in that the licensee failed to establish steady-state flow conditions at the outlet of the test piping prior to data collection necessary for the verification of check valve position. Additionally, operators used non-calibrated timing and liquid collection devices while obtaining data. The net effect of the procedural deficiencies was the collection of meaningless data.

.5 A finding described in Section 4OA2.2 of this report had, as its primary cause, a problem identification and resolution deficiency in that the licensee failed to identify and correct issues associated with the implementation of on-line risk management. As a result, protection of risk-significant equipment while in an elevated plant risk configuration was found to be inadequate on multiple occasions.

.6 A finding described in Section 4OA5 of this report had, as its primary cause, a problem identification and resolution deficiency in that the licensee failed to prevent recurrence of a significant condition adverse to quality. Specifically, the licensee did not take adequate corrective action to prevent the repetitive failure of the Division 1 ESW pump.

4OA5 Other Activities

Introduction: A self-revealed violation of 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Actions,” occurred when the Division 1 ESW pump failed during routine pump operation on May 21, 2004. The licensee rebuilt the pump in September 2003 following a similar failure. During the reassembly in September 2003, the parts used had nonconformances and correction of these nonconformances introduced stress risers to the affected keyways. Combined with a marginal design for the coupling, the coupling failed on May 21, 2004. The inspectors assessed this finding in accordance with IMC 0609 and Phase 3 analysis concluded that the finding was of very low safety significance. This finding was originally identified as **AV 05000440/2004011-02**.

Description: On May 21, 2004, the licensee started the Division 1 ESW pump in accordance with standard operating instructions. At 1:52 a.m., the control room received several alarms associated with the Division 1 ESW pump. Subsequent investigation revealed that the pump shaft had failed. The licensee investigated the shaft failure and concluded that a coupling had failed due to low design margin and the addition of stress risers during reassembly of the pump in September of 2003. The pump shaft consisted of four sections with four split-ring couplings to connect the sections and transfer power from the motor to the pump. Each of the couplings consisted of a two-piece split-ring, a coupling sleeve, two keys, and two setscrews. The licensee restored the pump to operability at 5:13 a.m. on May 29, 2004.

The licensee’s root cause team developed a series of failure scenarios and systematically reviewed each scenario to determine if available evidence supported the scenario. In addition, the team reviewed documentation, performed calculations, conducted interviews, and obtained laboratory data. During these investigations, the team discovered that during reassembly of the pump’s couplings, maintenance mechanics had removed .020" high spots in the keyways of three of four couplings. The tool used to perform this activity, called a broach, has large steel teeth to remove metal from the work piece. The broach used has square sides such that the keyway produced by the broach would have 90E corners. The sleeve design specified that the keyway would have a .030-.040" radius. Without a radius, stresses concentrated at the sharp angle and allowed for a crack to develop. Laboratory analysis of the failed coupling identified that the failed coupling had a keyway radius of .010" which resulted in a significant increase in stresses at the keyway corner. In addition to the broach, mechanics used files to fit pieces of the coupling together. During this work, the mechanics were not aware of the importance of the keyway radius.

Modeling of the coupling design using finite element analysis following the coupling failure in 2003 resulted in calculated stresses in excess of yield stress for an off-centered coupling and near yield for a properly aligned coupling. While the model was conservative in that it assumed a 90E keyway corner, the licensee did not pursue the results aggressively to refine the calculation such that margins could be thoroughly understood and evaluated. In their root cause report, the licensee concluded that the design was adequate when the coupling was properly assembled, i.e. aligned. The licensee relied on hand calculations to determine the acceptability of coupling designs and did not fully understand how easily the design could be challenged during installation. This represents a missed opportunity to prevent the shaft failure in May of 2004. Even though the licensee developed a new coupling design following the failure in September, the lack of understanding of the design contributed to the installation of the design not receiving a high enough priority to be implemented prior to the failure in May. Finite element analysis performed on the new coupling design demonstrated its higher margin to failure. While performing portions of the analysis, the licensee determined that maximum torque values provided by the pump vendor were incorrect. The vendor-provided values were for maximum steady-state torque when the maximum torque occurs during acceleration of the pump to normal operating speeds. Inclusion of the increased torque in the calculations resulted in reduced calculated margin.

Analysis: The inspectors evaluated this finding under the SDP. The inspectors concluded that this finding directly effected the mitigating system cornerstone objective of safety system availability. The inspectors evaluated the finding under Phase 1 of the SDP and determined a Phase 2 evaluation was needed. The inspectors based this conclusion on the loss of the Division 1 ESW safety function. With the shaft broken, the Division 1 ESW system could not perform its safety function. In addition, the loss of ESW resulted in inoperability of numerous supported systems including the Division 1 EDG, RHR 'A', and low pressure core spray systems. The Division 1 ESW pump was considered to be unavailable for a duration of 3 to 30 days. Based on the Phase 2 analysis, the inspectors concluded that a Phase 3 analysis was needed. The finding clearly affected the cross-cutting issue of Problem Identification and Resolution because the licensee failed to take adequate corrective action to prevent the repetitive failure of the Division 1 ESW pump.

Using the simplified plant analysis risk model a senior reactor analyst evaluated the safety significance of the failure using a duration of 10 days. Based on this evaluation, the analyst concluded that the finding was of very low safety significance. The analyst's risk evaluation found the increase in core damage frequency due to internal events to be of very low safety significance. The analyst ruled out the potential for common cause pump failure because the cause of the Division 1 ESW pump failure was known, the Division 2 ESW pump fulfilled its safety function while the Division 1 ESW pump was being repaired, and laboratory analysis of the Division 2 ESW pump coupling demonstrated that no incipient cracks existed. The analyst evaluated the risk contribution change due to external risk and concluded that when combined with internal risk, the significance remained Green. In addition, the analyst evaluated the change in large early release fraction and concluded that the finding remained Green. The analyst concluded the safety significance of the inspection finding based on the change in core damage frequency due to internal, external, and large early release fraction considerations, to be of very low safety significance.

Enforcement: Appendix B of 10 CFR Part 50, Criterion XVI, requires that measures be established to assure that conditions adverse to quality are promptly identified and corrected. It also requires that for significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action is taken to preclude repetition. Contrary to this requirement, the licensee did not take adequate corrective action to prevent the repetitive failure of the Division 1 ESW pump. Specifically, following the pump's failure in September 2003 the licensee determined that one of the causes of the failure was inadequate coupling design. The licensee developed an enhanced design that, if implemented, would have prevented recurrence. However, replacement of the pump's couplings with a more robust design did not occur until after the May 21, 2004 failure. Because this violation was of very low safety significance and it was entered into the licensee's corrective action program as CR 04-02598, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy **(NCV 05000440/2004011-02).**

4OA6 Meetings

.1 Exit Meeting

The inspectors presented the inspection results to Mr. L. Myers, Site Vice President and other members of licensee management at the conclusion of the inspection on October 6, 2004. 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

An interim exit meeting was conducted for:

- The radiation monitoring instrumentation and protective equipment program, and verification of the occupational and public PIs, with Mr. L. Myers on September 17, 2004.

4OA7 Licensee-Identified Violations

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

Cornerstone: Mitigating Systems

Technical Specification 5.4 states, in part, that procedures shall be established, implemented, and maintained as recommended in Regulatory Guide 1.33. Regulatory Guide 1.33 recommended the establishment of procedures for abnormal, off-normal, or alarm conditions and procedures for combating emergencies and other significant events. Licensee procedure ONI-C51, "Unplanned Change in Reactor Power or Reactivity," Rev. 16, was one of the licensee procedures established to meet this requirement. Revision 16 of the procedure was issued on August 30, 2004. A primary reason for the revision was to provide a flow chart format for supplemental operator actions. On September 2, 2004, during a pre-shift briefing which included the flow chart, the licensee identified numerous errors in the flow chart. With the errors, the licensee's ability to respond to a transient would be challenged and as such the procedure deficiency was considered to be a precursor to a more significant event. The licensee briefed the control room staffs on the flow chart errors and the correct actions to be taken if the flow chart was required prior to correction. A revised procedure was issued later that same day. The issue was entered into the licensee's corrective action program as CR 04-04567. The inspectors considered the issue to be of very low safety significance in that the errors were identified before use and as such had no actual impact.

Technical Specification 5.4 states, in part, that procedures shall be established, implemented, and maintained as recommended in Regulatory Guide 1.33. Regulatory Guide 1.33 recommended the establishment of procedures for the plant fire protection program. Licensee procedure PAP-1910, "Fire Protection Program," Rev. 8 was established to meet this requirement. Step 4.4.2.1 of PAP-1910 required fire protection system operation "in accordance with established System Operating Instructions (SOIs), Valve Line-Up Instructions (VLIs), Electrical Line-Up Instructions (ELIs), Off-Normal Instructions (ONIs), and Alarm Response Instructions (ARIs)." Contrary to this requirement, on April 23,2004, the licensee failed to restore the EDG room CO_2 system to standby readiness in accordance with SOI-P54(GAS), "Fire Protection System - Gas," Rev. 3. Specifically, the licensee failed to properly perform step 4.1.13 which required verification of a pilot pressure isolation valve in the locked open position. On April 28, 2004, while performing a test instruction to verify CO_2 storage tank pressure and level, a licensee fire protection technician observed the chain used to lock the valve was broken and subsequently determined the valve to be in the closed position. The licensee initiated an impairment and restored the system to standby status that same day. The issue was entered into the licensee's corrective action program as CR 04-02162. The inspectors reviewed this finding in accordance with IMC 0609, Appendix F. In concert with region based inspectors, the inspectors concluded that the finding was of very low safety significance due to the small change in core damage probability associated with this condition.

Cornerstone: Occupational Radiation Safety

Title 10 CFR 20.1902(a) requires licensees to post each radiation area with a conspicuous sign or signs bearing the radiation symbol and the words "CAUTION RADIATION AREA."

On August 25, 2004, an unposted radiation area was discovered in the turbine power building 620' elevation near the west roll-up door. A radiation protection technician was covering a job near the roll-up door in which workers were moving vendor equipment into the turbine power building. The technician noticed elevated readings on his survey meter, and upon investigation determined that there was a small area which had dose rates in excess of the 5 millirem/hour threshold which would require posting as a radiation area. The elevated readings were caused by shine from the 1N23 filter on the turbine power building 593' level which is directly below the 620' level. The licensee immediately posted the area as a radiation area and entered this issue into the corrective action system in CR 04-04426. This finding was of very low safety significance as there were no radiological exposure consequences to the individuals working in the area.

ATTACHMENT: SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

L. Myers, Vice President-Nuclear
F. von Ahn, General Manager, Nuclear Power Plant Department
R. Farrell, Radiation Protection Manager
F. Kearney, Operations Manager
J. Lausberg, Manager, Regulatory Compliance
T. Lentz, Director, Nuclear Engineering
J. Messina, Director, Performance Improvement
W. O'Malley, Maintenance Manager
R. Strohl, Superintendent, Plant Operations

Nuclear Regulatory Commission

See-Meng Wong, Senior Reactor Analyst, Office of Nuclear Reactor Regulation

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000440/2004013-01	NCV	Inadequate Instrumentation Calibration (Section 1REP.1.1)
05000440/2004013-02	NCV	Failure to Identify Most Severe Limiting Fuel Oil Return Line Fretting (Section 1REP.1.2)
05000440/2004013-03	NCV	Failure to Identify Misaligned Auxiliary Switch (Section 1R19)
05000440/2004013-04	NCV	Failure to Specify Adequate Testing Protocol and Acceptance Criteria (Section 1R22)
05000440/2004013-05	URI	Safety-System Unavailability for RHR (Section 4OA1.1)
05000440/2004013-06	FIN	Repetitive Failure to Implement On-Line Risk Management Strategy (Section 4OA2.2)
05000440/2004013-07	URI	Alert Due to Indicated Off-Gas System High Gas Radiation Levels (Section 4OA3.1)
05000440/2004011-02	NCV	Repeat Failure of ESW Pump Upper Shaft Coupling (Sections 4OA3.4 and 4OA5)

Closed

05000440/2004013-01	NCV	Inadequate Instrumentation Calibration (Section 1REP.1.1)

05000440/2004013-02	NCV	Failure to Identify Most Severe Limiting Fuel Oil Return Line Fretting (Section 1REP.1.2)
05000440/2004013-03	NCV	Failure to Identify Misaligned Auxiliary Switch (Section 1R19)
05000440/2004013-04	NCV	Failure to Specify Adequate Testing Protocol and Acceptance Criteria (Section 1R22)
05000440/2004013-06	FIN	Repetitive Failure to Implement On-Line Risk Management Strategy (Section 4OA2.2)
05000440/2003-005-01	LER	Technical Specification Violation/Loss of Safety Function Due to Air Bound Waterleg Pump (Section 4OA3.3)
05000440/2004-001-00 and 2004-001-01	LER	Emergency Service Water Pump Failure (Section 4OA3.4)
05000440/2004011-02	AV	Repeat Failure of ESW Pump Upper Shaft Coupling (Section 4OA5)
05000440/2004011-02	NCV	Repeat Failure of ESW Pump Upper Shaft Coupling (Sections 4OA3.4 and 4OA5)

Discussed

05000440/2002008-01	NCV	Failure to Perform TS Required Testing (Section1R22)
05000440/2002008-02	VIO	High Pressure Core Spray Pump Failure to Start (Section 1R19)
05000440/2003010-01	NCV	Failure to Communicate that the Motor Feed Pump Was to be Protected as Required by Online Risk Management Strategy (Section 4OA2.2)
05000440/2004006-01	VIO	Inadequate LPCS/RHR 'A' Fill and Vent Procedures Results In System Inoperability After Loss of Offsite Power (Section 4OA3.3)
05000440/2004011-02	AV	Repeat Failure of ESW Pump Upper Shaft Coupling (Section 4OA5)

LIST OF DOCUMENTS REVIEWED

The following is a list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspectors reviewed the documents in their entirety but rather that selected sections of 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.

1REP Equipment Availability and Functional Capability

Perry Nuclear Power Plant; Plant Health Report; First Quarter 2004
Perry Nuclear Power Plant; Plant Health Report; Second Quarter 2004
CR 04-03234; Diesel Loading in SOI-R43 Differs from Design Basis Loading; dated June 21, 2004
CR 04-03298; Diesel Fuel Oil Consumption Calculation Design Basis Loading; dated June 24, 2004
CR 04-03046; Additional Kilowatts on the Division 2 Standby Emergency Diesel Generator; dated June 3, 2004
IPE; Individual Plant Examination of the Perry Nuclear Power Plant; dated July 1992
Operations Standing Instruction - Division 1 and 2 D/G Guidance; dated June 25, 2004
CR 04-03379; Issues Remain on OD for CR's 04-03234 and 04-03298; dated June 30, 2004
CR 04-03241; Unsupported Double Root Valves 1G33F0057/F0058; dated June 21, 2004
DWG 302-0672-00000; Reactor Water Cleanup System; Rev. EE
USAR Figure 4.6-5; Control Rod Drive Hydraulic System; Rev. 13
Temporary Modification Technical Evaluation 04-0003; Isolate Pressure Relief Valve 1C11F0025B; dated March 15, 2004
Regulatory Applicability Determination; TM 04-0003, Isolate Pressure Relief Valve 1C11F0025B; Rev. 0
10 CFR 50.59 Screen; TM 04-0003, Isolate Pressure Relief Valve 1C11F0025B; Rev. 0
CR 04-03470; Maximum Room Temperature Not Considered in Minimum Starting Air Pressure; dated July 6, 2004
Calc M43-T01; Non SR Tolerance Calc for M43K010 A/B/C and M43 K020 A/B/C; dated March 1, 1985
1M43K0010A Calibration Data; dated August 28, 2003
1M43K0010B Calibration Data; dated June 25, 2001
CR 04-03576; Failure of 1E51-F0011 Leakage Rate During SVI-E51-T2001; dated July 12, 2004
PAP-1101; Inservice Testing of Pumps and Valves; Rev. 7
TAI-1101-2; Inservice Testing of ASME Section XI Valves; Rev. 0
Calc E51-022; Acceptance Criteria Calculation for Check Valve 1E51F0011 Exercise Close Test Performed in SVI-E51-T2001 and SVI-E51-T1272; Rev. 1
Pump/Valve Record of Corrective Action; 1E51-F0011 Failed Surveillance Test; dated July 14, 2004
CR 04-03833; DG Control Air Supply Filter Do Not Meet System Design Pressure Requirements; dated July 22, 2004
CR 04-03727; Div 1 and 2 DG Room Temp DLCO Missed; dated July 18, 2004

CR 04-03499; Error in Calculation Supporting an Operability Determination; dated July 7, 2004
CR 04-03993; M43 Temperature Instrument Accuracy and Resultant Compensatory Actions; dated July 30, 2004
M&C-14; Work Around Policy; dated February 15, 2000
Maintenance Rule Functions, Performance Criteria and Classifications database; dated June 17, 2002
Maintenance Rule Monitor Database; dated August 13, 2004
CR 03-00630; SVI Tech Spec Out of Allowable Band; dated February 7, 2003
CR 03-03886; Rad Monitor Spike Causes Entry into ONI-D17; dated June 14, 2003
CR 03-03980; ONI-D17 Entry Due to Failed Rad Monitor; dated June 21, 2003
CR 03-06528; ECC Temperature Control Valve Not Maintaining Temperature; dated December 5, 2003
CR 03-06739; 1P42-F665A Disconnect EF1A09-S Blown Fuses; dated December 21, 2003
CR 03-06315; Observations of P45 and P42 Temperatures; dated November 22, 2003
CR 03-01540; Latent Issue Review ESW and ECCW System Operation and Heat Load Issues; dated March 27, 2003
CR 03-5014; P42 Flow Element/Orifice Plate Thickness; dated August 28, 2003
CR 03-02842; Flow Balance Emergency Closed Cooling Loop 'A,' dated May 2, 2003
USAR Appendix 9A; Fire Protection Evaluation Report
SOI-P45(WTR); Fire Protection System- Water; Rev. 5
PAP-1910; Fire Protection Program; Rev. 8
Calc P54-124; Fire Protection Suppression System Water Supply Calculation; Rev. 1
CR 00-2834; RFA -In Order to Ensure Compliance with PAP-1914, Ensure Options; dated September 14, 2000
CR 01-3286; RFA-DES Recommendation Requested for Alternate Back-up P54 Pump Purchase; dated September 11, 2001
TM 04-009; Reroute Instrument Tubing for Reactor Recirculation Pump Seals; dated September 8, 2004
10CFR50.59 Screen 04-01193; Temporary Modification to Use Alternate Pressure Taps to Record/Monitor Differential Pressure across 1C11R5840; Rev. 0

1R01 Adverse Weather Protection

IPTE 2004-006; Zebra Mussel Treatment Termination Criteria; dated July 27, 2004
PTI-GEN-P0024; Mussel Treatment; Rev. 6
CR 02-03809; Zebra Mussel Treatment Post Job Critique; dated September 25, 2002

1R04 Equipment Alignment

Perry Nuclear Power Plant; Plant Health Report; First Quarter 2004
VLI-E12; Residual Heat Removal System; Rev. 5
Drawing 302-0641-00000; Residual Heat Removal System; Rev. WW
Drawing 302-0642-00000; Residual Heat Removal System; Rev. CC
Drawing 302-0643-00000; Residual Heat Removal System; Rev. SS
CR 04-02947; 3 Blown Mainline Fuses On E12-F004A; dated June 3, 2004
CR 04-01282; SPCU Pump Tripped While Performing RHR A Flush Activities; dated March 12, 2004

CR 04-01235; RHR System Flow Value Changed in SOI as a Non-Intent Change; dated March 10, 2004
CR 04-01107; OE 17833 - Follow Up to OE 14610, Small Pipe Failures in 'A' RHR System; dated March 4, 2004
CR 04-00311; SPCU Pump Trip During SOI-E12 Sect 7.12; dated January 23, 2004
CR 03-05631; RHR A Vibration in Alert Range; dated October 7, 2003
CR 03-04927; Spurious "RHR A Out of Service" Alarm; dated August 22, 2003
VLI-E51; Reactor Core Isolation Cooling; Rev. 6
SOI-E51; Reactor Core Isolation Cooling; Rev 14
CR 04-03680; 1E51F0022 Failed to Meet Its Stroke Time Close; dated July 15, 2004
DWG S-322-641-107; Residual Heat Removal; Rev. 0
SOI-M15; Annulus Exhaust Gas Treatment System; Rev. 7
VLI-M15; Annulus Exhaust Gas Treatment System (Unit 1); Rev 4

1R05 Fire Protection

DWG E-023-002; Fire Protection Evaluation Unit 1 Auxiliary and Reactor Buildings Plan - Elev. 574'-10"; Rev. 12
DWG E-023-010; Fire Protection Evaluation Unit 1 Auxiliary and Reactor Buildings Plan - Elev. 620'-6"; Rev. 12
USAR 9A.4.2.1.3; Fire Zone 1AB-1c
USAR 9A.4.2.1.9; Fire Zone 1AB-3a
USAR 9A.4.2.1.10; Fire Zone 1AB-3b
USAR 9a.4.2.1.6.1; Fire Area 1AB-1f
FPI-1AB; Auxiliary Building Unit 1; Rev. 2
FPI-0CC; Control Complex; Rev. 3
FPI-XFMER; Transformer Yard Areas; Rev. 1
USAR 9A.4.5.1.1; Fire Area 1DG-1a
DWG E-023–011; Fire Protection Evaluation- Units 1 and 2 Control Complex and Diesel Generator Buildings; Rev. 12

1R06 Flood Protection Measures

CR 04-03518; Building Roof Drains; dated July 7, 2004
Individual Plant Examination of External Events for Severe Accident Vulnerabilities; dated June 1996
RCN 8636-800-02; Storm Drain/Catch Basin System; Rev. 0
Design Specification for Concrete Structures Outside Containment; dated September 3, 1974
CR 04-03518; Building Roof Drains; dated July 7, 2004

1R07 Heat Sink Performance

PTI-E22-P0007; HPCS Diesel Generator Jacket Water Heat Exchanger Performance Testing; Rev. 2
Division 3 EDG Performance Test Historical Q Trend; dated September 1, 2004
Division 3 EDG Performance Test Historical ff Trend; dated September 1, 2004
Division 3 EDG Performance Test Historical U Trend; dated September 1, 2004

GL 89-13; Service Water System Problems Affecting Safety-Related Equipment; dated July 18, 2989
Letter PY-CEI/NRR-1121; PNPP Response to Generic Letter 89-13; dated January 26, 1990
Letter PY-CEI/NRR-1328L; Supplemental Response to Generic Letter 89-13; dated March 1, 1991
Letter PY-CEI/NRR-1734L; Implementation of Generic Letter 89-13; dated April 8, 1994

1R13 Maintenance Risk Assessments and Emergent Work Control

PYBP-DES-001; On-Line Risk Assessment Reference Guide; Rev. 2
Site wide email; YELLOW Risk On Tuesday, 6/29; dated June 28, 2004
PYBP-POS-2-2; Protected Equipment Postings; Rev. 2
Protected Equipment Posting Checklist; Division 3 D/G Unavailable For TRD Inspection; dated June 28, 2004
Perry Work Implementation Schedule; Week 4, Period 6
Perry Work Implementation Schedule; Week 5, Period 6
Probabilistic Safety Assessment; Week 4, Period 6; Rev. 0
Perry Work Implementation Schedule; Week 2, Period 7
Probabilistic Safety Assessment; Week 2, Period 7; Rev. 1

1R14 Operator Performance During Non-routine Evolutions and Event

WO 200104550; Unit. Auxiliary Transformer Relay Panel; Rev. 0

1R19 Post-Maintenance Testing

SVI-D17-T8050; OG Vent Pipe Noble Gas Radiation Monitor Calibration fro 1D17-K836; Rev. 4
ICI-C-D17-18; Calibration of Victoreen Beta Channels (C-D17-18); Rev. 2
WO 200035070; Interbus Transformer Supply Breaker; Rev. 1
SVI-C11-T2004; Scram Discharge Volume Vent and Drain Valves Operability Test; Rev. 9
WO 200109302; Air To Scram Disch Vol Drain; Rev. 0
CR 04-04316; RFA-Use of Tray x1126 as a Work Platform for 1C11F0009; dated August 19, 2004
CR 04-04255; Procurement of Valve for WO 200109302; dated August 17, 2004
CR 04-04266; Document Delay in Procurement for WO 200109302; dated August 18, 2004
CR 04-04218; SVI-C11-F180 and 1C11F181 Failed Stroke Times; dated August 16, 2004
CR 04-04266; Document Delay in Procuring Material for WO 200109302; dated August 18, 2004
WO 200108564; Adjust Aux Switch per GEI-135; dated August 13, 2004
CR 04-04197; Aux Contact Switches Found With Questionable Alignment on P47 Breaker; dated August 13, 2004
CR 04-04485; Unanticipated Breaker Response During Test; dated August 30, 2004
SOI-P47; Control Complex Chilled Water System; Rev. 10

GEI-135; ABB Power Circuit Breakers 5 KV Types 5HK250 and 5HK350 Maintenance; Rev. 6
SOI-R22; Metal Clad Switchgear 5-15KV; Rev. 15
SVI-E22-T2001; HPCS Pump and Valve Operability Test; Rev. 16
WO 200053605; HPCS First Test Valve to CST; Rev. 0
PMI-0030; Maintenance of Limitorque Valve Operators; Rev. 7

1R22 Surveillance Testing

DWG 302-0356-00000; HPCS Diesel Generator Fuel Oil System; Rev. T
SVI-R45-T2003; Division 3 Diesel Generator Fuel Oil Transfer Pump and Valve Starting Air Check Valve Operability Test; Rev. 8
CR 04-03416; Incorrect Gauge Readability Used During SVI-R45-T2003; dated July 1, 2004
SVI-M17-T0410-A; Containment Vacuum Breaker Differential Pressure Actuation Channel Functional For 1M17-N018 (Division 1); Rev. 4
SVI-E51-T2001; RCIC Pump and Valve Operability Test; Rev. 17
CR 04-03576; Failure of 1E51-F0011 Leakage Rate During SVI-E51-T2001; dated July 12, 2004
PAP-1101; Inservice Testing of Pumps and Valves; Rev. 7
TAI-1101-2; Inservice Testing of ASME Section XI Valves; Rev. 0
File G241; Gould Electronics Equipment; Rev. 3
SVI-E22-T0196-G; HPCS Suppression Pool High Level Channel G Calibration for 1E22-N055G; Rev. 3
SVI-M14T9314; Type C Local Leak Rate Test of M14 Penetration V314; Rev. 10
SVI-M14-T9313; Type C Local Leak Rate Test of M14 Penetration V313; Rev. 10
TAI-1120-1; Type “B” and “C” Local Leak Rate Calculations for 0.6 L_a and Secondary Containment Bypass; Rev. 3
PAP-1120; Leak Testing Program; Rev. 4
SVI-E31-T0075-A; MSL High Flow Channel A Calibration for 1E31-N086A and 1E31-N088A; Rev. 4
SVI-E22-T2001; HPCS Pump and Valve Operability Test; Rev. 16

2OS1 Access Control to Radiologically Significant Areas

04-04426; Unposted Radiation Area Found; dated August 25, 2004

2OS3 Radiation Monitoring Instrumentation and Protective Equipment

PCM-1B; L70L007F Calibration; dated March 8, 2004
SAC-4; L70L003E Calibration; dated August 4, 2004
AMP-100; L70L075C Calibration; dated May 18, 2004
Bicron Analyst; L70L095B Calibration; dated July 7, 2004
Bicron Tech 50; L70L131F Calibration; dated April 20, 2004
Sam-9; L70L504I Calibration; dated April 29, 2004
SPM-906; L70L0009J Calibration; dated June 16, 2004
Gamma-60; L70L009E Calibration; dated May 21, 2004
ASP-1; L70L091H Calibration; dated May 4, 2004

Canberra Whole Body Counter; L70L600A Calibration; dated August 28, 2004
Electronic Dosimeter DMC 2000; 236610 Calibration; dated June 15, 2004
Electronic Dosimeter DMC 2000; 237013 Calibration; dated June 11, 2004
Electronic Dosimeter DMC 2000; 238000 Calibration; dated June 16, 2004
Teletector; L70L070B Calibration; dated July 27, 2004
Teletector; L70L070G Calibration; dated June 10, 2004
AMS-4; L70L231E Calibration; dated May 23, 2004
AMS-4; L70L231H Calibration; dated May 28, 2004
Gilian Lapel Air Sampler; L70L222A Calibration; dated June 21, 2004
Gilian Lapel Air Sampler; L70L222B Calibration; dated June 21, 2004
PY-SVI-D17T0374; Drywell Atmosphere Gaseous And Particulate Radiation Monitor Calibration; dated October 17, 2003
PY-PTI-D17P1680; Containment Atmosphere Radiation Monitor Calibration; dated July 7, 2003
PTI-D17P1670; Drywell Atmospheric Radiation Monitor Calibration; dated January 16, 2003
NEI 99-02; Performance Indicators; Revision 2
RETS/ODCM; Monthly Radiological Effluent Occurrences; dated September 2003 through August 2004
RCS Dose Equivalent Iodine Monthly Reports; dated August 2003 through August 2004
HPI-B0004; Personnel Radiation Dose Calculations; Revision 8
RCS Gross Activity Report; dated September 16, 2004
Access Control Alarm Report; dated September 14, 2004
Occupational Exposure Control Effectiveness (Monthly PI); dated September 2003 through August 2004
Updated Final Safety Analysis Report; Section 12.3.4 Area Radiation and Airborne Radioactivity Monitoring Instrumentation
PY-C-04-02; NQA Audit report, April 1 - June 30, 2004; dated August 20, 2004
PY-C-04-01; NQA Audit report, January 5 - March 31; dated April 30, 2004
688-RPS-2004; RP Collective Significance Self-Assessment; dated July 22, 2004
698-RPS-2004; Condition Report Binning Report for 1st Quarter 2004
04-03381; MSL A Upscale Alarm Set-point Discrepancy; dated June 30, 2004
04-04508; Gamma Spectroscopy System Not Giving Complete Off-Gas Reports; dated August 31, 2004
04-01280; Radioactive Source Damaged; dated March 12, 2004
04-01513; PCR-SOI-D17 Airborne Radiation Monitors; dated March 25, 2004
04-01520; Testing Of Beta Sensitive Whole Body Contamination Monitors; dated March 25, 2004
04-01931; Radiation Instrument Failure; dated April 14, 2004
04-02345; Software Testing Reveals An Error In PCM-2 Algorithm; dated May 10, 2004
04-02484; RP Dose Rate Meter Failed Daily Response Check; dated May 15, 2004
04-02510; Portable Radiation Detection Instrument Failure; dated May 17, 2004
04-02573; MG Dosimeter Not Activated At Access Control; dated May 20, 2004
04-02749; DMC-2000 Dosimeter Malfunction; dated May 26, 2004
04-04036; Radiation Levels Above Posting Requirements Found Outside TP Building; dated August 4, 2004
04-02825; MG Failed To Turn Off In Reader; dated May 30, 2004

04-03649; Sporatic MG Dose Rate Alarm; dated July 14, 2004
04-03932; Meter Failed In The Field; dated July 28, 2004

4OA1 Performance Indicator Verification

CR 04-01844; HPCS Unavailability Approaching NRC Green-White Unavailability Threshold; dated April 9, 2004
Plant Narrative Logs; January 1, 2004, through June 30, 2004
Engineering system unavailability tracking logs; second quarter 2004
Engineering system unavailability tracking logs; first quarter 2004

4OA2 Identification and Resolution of Problems

CR 03-06022; Discrepancy Between Risk Card and PWIS PSA Protected Lists; dated November 3, 2003
CR 04-03361; Protected Areas Not Posted IAW PYBP-POS-2-2; dated June 29, 2004
PYBP-POS-2-2; Protected Equipment Postings; Rev. 2
CR 02-01555; Protected Train Postings Need Improvement; dated May 21, 2002
CR 04-02782; Shutdown Safety Posting Altered - ESW Pump B; dated May 28, 2004
CR 03-06057; Protected Posting Requirements; November 5, 2003

4OA3 Event Followup

EPI-A1, Emergency Plan Implementing Instruction; Rev. 10
Operator Logs, dated July 20, 2004
CR 04-03779; Alert Declared-EAL-HA1; dated July 20, 2004
ONI-D17; High Radiation Levels Within Plant; Rev. 9
RPI-0506; Response to Area Radiation Monitor Alarms, Airborne Radiation Monitor Alarms and Radioactive Spills; Rev. 2
CR 04-03987; EAL HA1 CADAP Run; dated July 30, 2004
CR 04-03145; Feedwater Temperature RTD 1B21N0041D; dated June 16, 2004
CR 04-04200; RFA: Re-Evaluate Effect of RTD/Transmitter Cal on Reactor Thermal Power; dated August 13, 2004
LER 2004-001; Emergency Service Water Pump; Rev. 0
LER 2004-001; Emergency Service Water Pump; Rev. 1

LIST OF ACRONYMS USED

ARI	alarm response instruction
ASME	American Society of Mechanical Engineers
AV	apparent violation
CADAP	Computer-Assisted Dose Assessment Program
CCCW	control complex chilled water
CFR	*Code of Federal Regulations*
CR	condition report
CST	condensate storage tank
DEI	Dose Equivalent Iodine
DHR	decay heat removal
EDG	emergency diesel generator
ELI	electrical line-up instruction
ESW	emergency service water
FAQ	Frequently Asked Question
FENOC	FirstEnergy Nuclear Operating Company
gpm	gallons per minute
HPCS	high pressure core spray
IMC	Inspection Manual Chapter
LCO	limiting condition for operation
LER	Licensee Event Report
MFP	motor feed pump
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NLO	non-licensed operator
NRC	Nuclear Regulatory Commission
OA	Other Activities
ODCM	Offsite Dose Calculation Manual
OE	Operability Evaluation
ONI	Off-Normal Instruction
PI	performance indicator
PMT	post-maintenance testing
PNPP	Perry Nuclear Power Plant
RCIC	reactor core isolation cooling
RETS	Radiological Environmental Technical Specifications
RHR	residual heat removal
SDP	significance determination process
SOI	system operating instruction
SVI	surveillance instruction
TS	Technical Specification
URI	Unresolved Item
USAR	Updated Safety Analysis Report
VLI	valve lineup instruction