July 20, 2005

Mr. R. Anderson
Vice President
FirstEnergy Nuclear Operating Company
Perry Nuclear Power Plant
10 Center Road, A290
Perry, OH 44081

SUBJECT: PERRY NUCLEAR POWER PLANT
NRC INTEGRATED INSPECTION REPORT 05000440/2005006

Dear Mr. Anderson:

On June 30, 2005, 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 June 30, 2005, with you and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel. In addition to the routine NRC inspection and assessment activities, Perry performance is being evaluated quarterly as described in the Assessment Follow-up Letter - Perry Nuclear Power Plant, dated August 12, 2004. Consistent with Inspection Manual Chapter (IMC) 0305, "Operating Reactor Assessment Program," plants in the multiple/repetitive degraded cornerstone column of the Action Matrix are given consideration at each quarterly performance assessment review for (1) declaring plant performance to be unacceptable in accordance with the guidance in IMC 0305; (2) transferring to the IMC 0350, "Oversight of Operating Reactor Facilities in a Shutdown Condition with Performance Problems," process; and (3) taking additional regulatory actions, as appropriate. On May 20, 2005, the NRC reviewed Perry operational performance, inspection findings, and performance indicators during the first quarter of 2005. Based on this review, we concluded that Perry is operating safely. We determined that no additional regulatory actions, beyond the already increased inspection activities and management oversight, are currently warranted.

Based on the results of this inspection, eight findings of very low safety significance, seven 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.

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. Satorius
Director
Division of Reactor Projects

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

Enclosure: Inspection Report 05000440/2005006
w/Attachment: Supplemental Information

cc w/encl: G. Leidich, President - FENOC
J. Hagan, Chief Operating Officer, FENOC
D. Pace, Senior Vice President Engineering and Services, FENOC
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Director, Regulatory Affairs
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Ohio State Liaison Officer
R. Owen, Ohio Department of Health

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***See previous concurrence**

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U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-440
License No:	NPF-58
Report No:	05000440/2005006
Licensee:	FirstEnergy Nuclear Operating Company (FENOC)
Facility:	Perry Nuclear Power Plant, Unit 1
Location:	P.O. Box 97 A210 Perry, OH 44081
Dates:	April 1 through June 30, 2005
Inspectors:	R. Powell, Senior Resident Inspector M. Franke, Resident Inspector J. Rutkowski, Resident Inspector, Davis-Besse C. Acosta Acevedo, Reactor Engineer G. Roach, Reactor Engineer
Approved by:	C. Lipa, Chief Branch 4 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000440/2005006; 04/01/2005 - 06/30/2005; Perry Nuclear Power Plant; Adverse Weather, Equipment Alignment, Maintenance Risk Assessments and Emergent Work Control, Surveillance Testing, Identification and Resolution of Problems, Event Followup, Other Activities.

This report covers a 3-month period of baseline inspection. The inspection was conducted by the resident and regional inspectors. This inspection identified eight Green issues, seven 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. <u>Inspector-Identified and Self-Revealed Findings</u>

Cornerstone: Initiating Events

- Green. The inspectors identified a finding of very low significance for the licensee's failure to sufficiently coordinate and adequately prepare for the onset of hot weather prior to May 1, 2005. Specifically, the licensee failed to complete work associated with critical components, in accordance with established expectations that specified completion prior to April 30, 2005. As a result, critical tasks had not been completed prior to the onset of near record warm weather beginning June 5, 2005.

  The inspectors determined that the issue was more than minor because, if left uncorrected, the finding would become a more significant safety concern. The finding was also associated with the reactor safety initiating events cornerstone and affected the cornerstone's objective of limiting the likelihood of events that upset plant stability. The finding was of very low safety significance because no safety-related functions or mitigating systems were rendered inoperable and no plant transient was initiated. No violation of NRC requirements occurred. (Section 1R01)

- Green. A finding of very low safety significance and a violation of 10 CFR 50.65(a)(4) was self-revealed during preparation for an electrical distribution panel F1F14 outage on April 4, 2005. The reactor was shutdown at the time of the event. Specifically, the licensee failed to identify the impact of planned breaker manipulations on the fuel pool cooling and cleanup (FPCC) system. Per an Operations Evolution Order, the K-1-D electrical bus was de-energized which de-energized the fuel pool filter demineralizer (FPFD) control panel, H51-P173. As a result, the demineralizer flow control valves shut. The flow control valve repositioned and reduced FPCC flow to the reactor cavity pool from 720 gpm to 520 gpm and flow to the spent fuel pool from 700 gpm to 600 gpm. At the time of the event, FPCC was the primary method of decay heat removal. Numerous alarms were received in the control room. Control room personnel assessed the transient and within 30 minutes opened the FPCC fuel pool filter demineralizer bypass valve to restore proper flow to the reactor pool and spent fuel pool. The primary cause of this finding was related to the cross-cutting area of Human Performance in that licensee personnel failed to properly assess the impact of a planned maintenance activity on a key shutdown safety function.

The finding was more than minor because the failure to identify the impact of the planned maintenance activity adversely affected a protected train of equipment providing the key shutdown safety function of decay heat removal. The finding was associated with the reactor safety initiating events cornerstone attribute of configuration control and it affected the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown operations in that it adversely affected the FPCC decay heat removal function. The finding was of very low safety significance because FPCC decay heat removal function was restored promptly on discovery and alternate decay heat removal systems remained available. The issue was a Non-Cited Violation of 10 CFR 50.65(a)(4) which required the licensee to assess and manage the increase in risk that may result from proposed maintenance activities. (Section 1R13)

- Green. A finding of very low safety significance and a violation of Technical Specification (TS) 5.4, "Procedures," was self-revealed during preparation for Division 2 loss of off-site power (LOOP) testing on April 5, 2005. The reactor was shutdown at the time of the event. Valves in the cooling water supply path to the FPCC system heat exchangers were unintentionally isolated. This resulted in loss of decay heat removal from the reactor pool and spent fuel pool for approximately two hours. Operators subsequently discovered the valves were out of position, restored the system to the correct lineup, and restored decay heat removal. The primary cause of this finding was related to the cross-cutting area of Human Performance in that licensee personnel failed to implement procedures as written. Specifically, the licensee personnel performing the test preparations performed a procedure step out of sequence which resulted in the loss of cooling water to the FPCC heat exchangers.

  The finding was more than minor because the failure to follow procedures resulted in a loss of cooling for the reactor pool and spent fuel pool for approximately two hours. The finding was associated with the reactor safety initiating events cornerstone attribute of configuration control, and it affected the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown operations in that it resulted in loss of FPCC decay heat removal function. The finding was of very low safety significance because the FPCC decay heat removal function was restored promptly on discovery and alternate decay heat removal systems remained available. The issue was a Non-Cited Violation of TS 5.4 which required the implementation of written surveillance test procedures. (Section 1R22.1)

- Green. A finding of very low safety significance and a violation of TS 5.4, "Procedures," was self-revealed on April 21, 2005. While the plant was shutdown for a refuel outage, the licensee conducted LOOP response testing of the Division 3 high pressure core spray (HPCS) emergency diesel generator (EDG). The procedure required the installation of a jumper between terminal points in the HPCS preferred source breaker cubicle, EH1303. Contrary to procedure, technicians installed the jumper in the alternate preferred source breaker cubicle EH1302. The error was identified when control room operators attempted to close breaker EH1302 and it did not close as expected. The jumper was subsequently removed from the EH1302 cubicle without consequence. The primary cause of this finding was related to the cross-cutting issue of Human Performance. Specifically, licensee technicians failed to perform the procedure as written and failed to use independent verification and, as a result, installed the jumper in the wrong cubicle.

The finding was more than minor because it could reasonably be viewed as a precursor to a more significant event. Additionally, if left uncorrected, the failure to follow procedures affecting safety-related equipment would become a more significant safety concern. The inspectors determined that the finding was of very low safety significance because the finding did not involve a loss of safety function. (Section 1R22.2)

Cornerstone: Mitigating Systems

- Green. The inspectors identified a finding of very low safety significance and a violation of 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action,” for the licensee’s failure to identify and correct a condition adverse to quality. Specifically, the licensee failed to identify the inadequate thread engagement of two bolts on the residual heat removal (RHR) 'B’/’C' waterleg pump discharge flange. Inspectors identified the non-conforming condition during a walkdown of the RHR 'C' system while RHR 'C' was designated as the primary water inventory source for the shutdown reactor. Inspectors promptly reported the condition to the licensee and the licensee entered it into the corrective action program. The licensee performed corrective maintenance to fix the inadequate thread engagement on May 19, 2005. 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 viewed as a precursor to a more significant event. The failure to identify and correct inadequate thread engagement on bolted connections could allow premature failure and leakage from the connection. Additionally, the finding was associated with the reactor safety mitigating systems cornerstone and affected the cornerstone’s objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Failure to identify and correct non-conforming conditions on safety-related equipment degrades the reliability of the system to perform its safety function. The inspectors determined that the finding did not involve the loss of safety function and therefore concluded that the finding was of very low safety significance. (Section 1R04)

- Green. A finding of very low safety significance and a violation of 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” was self-revealed on February 17, 2005, when the Division 2 EDG testable rupture disc (TRD) required excess force to lift during surveillance testing. A newly designed Division 2 TRD had been installed in October 2004 in an effort to address long-standing equipment performance issues. A similar design was installed on the Division 1 EDG in November 2004 and on the Division 3 EDG in April 2004. After the test failure on February 17, 2005, subsequent licensee inspection identified that the disc was warped. Due to potential common cause issues, the licensee declared all three EDGs inoperable and entered TS Limiting

Condition for Operation (LCO) 3.0.3. The licensee unlatched all EDG TRDs to restore operability. The licensee's design review for the TRD did not adequately consider the potential for and the effect of deformation of the TRD disc due to heat. Additionally, the licensee's testing of the design modification was determined to be inadequate. The primary cause of this finding was related to the cross-cutting area of Human Performance in that licensee personnel failed to perform an adequate design review.

The finding was more than minor because it affected the mitigating systems cornerstone objective of ensuring the availability, reliability, and capability of the EDGs in response to initiating events. Specifically, if the TRD failed to lift at the appropriate pressure, excessive back-pressure would adversely affect fuel consumption rates. Further, if the TRD failed to open with the normal EDG exhaust blocked, conditions could be established which would result in stalling of the EDG. The finding was determined to be of very low safety significance because Significance Determination Process Phase 3 analysis determined the issue to not be greater than Green due to the low frequency of seismic and tornado events. (Section 4OA3.1)

- Severity Level IV. The inspectors identified a Severity Level IV Non-Cited Violation associated with the failure to report residual heat removal (RHR) train 'B' unavailability from May 29, 2004, through June 3, 2004, while the emergency service water train 'B' was inoperable for pump repairs. The second quarter 2004 data reported to the NRC included RHR 'A' unavailability following failure of the ESW 'A' pump on May 21, 2004, but did not include the subsequent RHR 'B' unavailability. Prior to removing the ESW 'B' pump from service, the licensee developed a reactor pressure vessel feed and bleed method which they subsequently credited as an alternate decay heat removal system when calculating RHR system unavailability. The inspectors, however, reviewed the definitions and guidance contained in Nuclear Energy Institute (NEI) 99-02, "Regulatory Assessment Indicator Guideline," Rev. 2, and could not conclude that the licensee's method met the "NRC approved method of decay heat removal." Due to the inspectors' concerns, the licensee submitted a "Frequently Asked Question." On May 19, 2005, the NRC determined that "NRC approval means a specific method or methods described in the technical specifications." As a result, the licensee recalculated and resubmitted RHR system unavailability on June 17, 2005. Had the performance indicator (PI) data been properly reported in the second quarter of 2004, the PI color would have been White. The failure to properly report the PI was considered a Severity Level IV Non-Cited Violation of 10 CFR 50.9. (Section 4OA5.2)

Cornerstone: Barrier Integrity

- Green. A finding of very low safety significance and a violation of 10 CFR 50, Appendix B, Criterion XII, "Control of Measuring and Test Equipment" was self-revealed on May 6, 2005. Specifically, on April 30, 2005, with the plant in a cold shutdown condition, the licensee installed temporary test gages to the tailpiece of residual heat removal (RHR) test connection isolation valve E12-F059B and to the test connection on the low pressure side of leak detection system (LDS) differential pressure detector E31-N077B associated with the reactor water clean-up (RWCU) return to the feedwater system flow instrument. The gages were installed to support operability testing of RWCU check valve G33-F052B. Contrary to the Perry Problem Solving Plan associated with work order (WO) 200147914, operators failed to remove the test gages following testing and prior to plant start-up. On May 6, 2005, a non-licensed operator in the RHR 'A' room noted that the temporary gage connected downstream of E12-F059B was still installed. After an extent of condition review was performed by the licensee, a second gage installed in the RWCU/LDS was identified. The primary cause of the finding was related to the cross-cutting issue of Human Performance in that the gages were not removed per the WO procedure.

The inspectors determined that leaving low pressure (300 psig) rated test equipment installed in a system (RWCU) that experiences normal operating pressure conditions of approximately 1000 psi was a performance deficiency warranting significance evaluation. The inspectors determined that the issue was more than minor because it could reasonably be viewed as a precursor to a more significant event. The inspectors determined that the finding was of very low safety significance because the finding only resulted in a degradation in the radiological barrier function of the Auxiliary Building and the finding did not result in an actual open pathway in the physical integrity of the reactor containment or involve an actual reduction in defense-in-depth for the atmospheric pressure control or hydrogen control functions of the reactor containment.
(Section 4OA2.3)

B. **<u>Licensee-Identified Violations</u>**

One violation of very low safety significance, which was identified by the licensee, has been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee’s corrective action program. This violation is listed in Section 4OA7 of this report.

Report Details

Summary of Plant Status

The plant began the inspection period in Mode 5 due to refueling outage (RFO) 10. Following completion of outage activities, the reactor achieved criticality at 5:21 p.m. on May 3, 2005. The plant entered Mode 1 at 3:04 p.m. on May 6, 2005, and the unit synchronized to the grid at 9:43 p.m. later that same day. After a series of power maneuvers to support control rod line adjustments and digital feedwater testing, the plant reached 100 percent power on May 16, 2005. The unit remained at or near 100 percent power until May 27, 2005, when power was reduced to 98 percent to insert control rod 06-35 for accumulator maintenance. The unit returned to 100 percent power later that same day. Accumulator maintenance was completed and the unit reduced power to 85 percent on May 29, 2005, to withdraw the control rod. The unit returned to 100 percent later the same day and remained at or near 100 percent power for the remainder of the inspection period.

1. REACTOR SAFETY

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

1R01 Adverse Weather (71111.01)

a. Inspection Scope

During June 2005 the inspectors reviewed the facility design and the licensee's procedures to determine whether the emergency service water (ESW) system would remain functional when challenged by adverse weather conditions, such as increasing lake temperatures. Additionally, the inspectors reviewed the licensee's 2003 summer seasonal readiness critique to determine whether recommendations and corrective actions were implemented in a timely manner. The inspectors also walked down selected areas to evaluate plant equipment susceptible to high temperatures. Finally, the inspectors reviewed the status of licensee summer preparation WOs to determine if the work was completed in a timely manner. This inspection constituted one system inspection sample.

b. Findings

Introduction: The inspectors identified a finding of very low safety significance for the licensee's failure to sufficiently coordinate and adequately prepare for the onset of hot weather prior to May 1, 2005. Specifically, the licensee failed to complete work associated with critical components in accordance with established expectations specifying completion prior to April 30, 2005. As a result, critical tasks had not been completed prior to the onset of near record warm weather beginning June 5, 2005.

Description: On June 13, 2005, the inspectors reviewed the status of the licensee's summer preparation activities. The inspectors noted that the licensee had previously initiated condition report (CR) 05-03742, "Summer Preparations Not in Compliance With NOBP-WM-2301 ["Seasonal Readiness," Rev. 0]," on April 24, 2005. The inspectors noted the licensee's CR closure comments identified staff vacancies, forced outages, and RFO10 as reasons for the performance deficiency. Despite the identified procedure non-compliance (specifically, NOBP-WM-2301 required scheduling of all summer readiness orders prior to April 30), no corrective actions were assigned.

The inspectors noted that average monthly high temperature for Perry, Ohio increases from 56 °F in April to 77 °F in June. As such, the licensee's expectation that summer preparedness activities be completed by April 30 appeared reasonable.

The inspectors reviewed the licensee's summer preparation work list dated May 25, 2005, and observed that 28 WOs were open or had yet to start. Of the 28 WOs, 11 were associated with critical components. The critical WOs were associated with the main generator transformer cooling coils and the containment vessel cooling system air handling units. Inadequate cooling to either the main generator transformer or the containment vessel could result in a plant transient.

On June 5, 2005, northeast Ohio experienced a period of near record warm weather. Temperatures at the plant reached 88 °F. At the time of this temperature excursion, 19 summer preparation WOs had yet to be completed, including 5 which were coded as critical.

The inspectors determined that the licensee's inability to schedule and execute seasonal work was a recurring problem. Specifically, the inspectors identified that on May 18, 2003, the licensee initiated CR 03-03338, "RFO9 Extension Causing Seasonal Readiness Preps To Be Delayed Beyond 6/1/03." The content of CR 03-03338 was similar to CR 05-03742 in that a planned refueling outage which extended beyond the original restart date was identified as the cause of the licensee's failure to adequately perform summer readiness activities. The CR was also similar in that no corrective actions were established. Another recent example of the licensee's performance deficiencies was documented in CR 04-05920, "Late Performance of Winterization Activities," dated November 16, 2004.

The inspectors reviewed the licensee's summer 2003 critique and observed that it identified schedule adherence as an area for improvement. The inspectors requested the licensee's summer 2004 critique which was required to have been completed by the predecessor to NOBP-WM-2301, Work Control Section Desk Guide 09, "Seasonal Readiness Desk Guide," but were informed by the licensee that contrary to the requirement, a critique was not performed. The licensee entered this performance deficiency into their corrective action program as CR 05-05052 and CR 05-05053. The inspectors identified that on October 14, 2003, the licensee initiated CR 03-05724, "Critique For Winter Preparations for 2002 Was Not Performed." The CR was initiated after the inspectors had requested the critique report. Corrective action was assigned and completed to transfer responsibility for conducting the critique from the plant engineering section to the work control section, but action was unsuccessful in resolving the problem.

Analysis: The inspectors determined that not sufficiently coordinating and being adequately prepared for the onset of hot weather prior to May 1, 2005, was a performance deficiency warranting a significance evaluation in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Disposition Screening," issued on May 19, 2005. The inspectors determined that the issue was more than minor because, if left uncorrected, the finding would become a more significant safety concern. The finding was also associated with the reactor safety initiating events cornerstone and affected the cornerstone's objective of limiting the likelihood of events that upset plant stability.

Using IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors answered "no" to the three screening questions in the Phase 1 Screening Worksheet under the Initiating Events column. Based on the answers to the screening questions the inspectors concluded that the issue was a finding of very low safety significance.

Enforcement: The inspectors determined that no violation of regulatory requirements had occurred since the licensee's governing procedures were not TS 5.4 procedures and the lack of coordination and preparation for hot weather had not resulted in the actual loss of any safety-related function or plant transient for the current summer season. **(FIN 05000440/2005006-01)**

1R04 Equipment Alignment (71111.04)

.1 Semi-Annual Complete System Walkdown

a. Inspection Scope

The inspectors performed a complete walkdown of accessible portions of the ESW system to verify system operability during the week of May 2, 2005. The ESW system was selected due to its risk significance and current system health status. The inspectors used 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 Report, outstanding maintenance work requests, and a sampling of licensee CRs to determine whether problems and issues were identified, and corrected, at an appropriate threshold. The documents used for the walkdown and issue review are listed in the attached List of Documents Reviewed. This constituted one sample.

b. Findings

No findings of significance were identified.

.2 Quarterly Partial System Walkdowns

a. Inspection Scope

The inspectors conducted partial walkdowns of the system trains listed below to determine whether 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 (samples):

- the nuclear closed cooling (NCC) system while the system was the primary method of decay heat removal on April 7, 2005;
- the low pressure core spray (LPCS) system while the system was the primary method of reactor coolant system inventory control on April 14, 2005; and
- the RHR 'C' system while the system was the primary method of reactor coolant system inventory control on April 25, 2005.

b. Findings

Introduction: Inspectors identified a finding of very low safety significance and a violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," for the licensee's failure to identify a condition adverse to quality. Specifically, the licensee failed to identify and correct inadequately threaded bolts on the RHR 'B'/'C' waterleg pump discharge flange.

Description: On April 25, 2005, inspectors conducted a partial walkdown of the RHR 'C' system. Inspectors observed that two bolts on the RHR 'B'/'C' waterleg pump discharge flange appeared to have inadequate thread engagement. A subsequent walkdown of the system by licensee engineering personnel confirmed the inadequate thread engagement of two bolts on the discharge flange. One fastener was short by 1½ threads and the other fastener was short by ½ of a thread. The identified issue was entered into the licensee's corrective action program as CR 05-03800. The licensee subsequently performed corrective maintenance to fix the inadequate thread engagement on May 19, 2005.

Inspectors contacted the RHR system engineer who reported that the last time maintenance had been performed on the flange was on August 22, 2000, using a Fix-It-Now team WO 00-007806. The purpose of this maintenance was to correct a condition of inadequate thread engagement of one nut on the flange. The inadequately threaded nut was identified during a licensee walkdown of the system pursuant to the investigation of the extent of condition of a Category 1 CR and associated root cause evaluation concerning inadequate thread engagement on bolted connections, CR 00-2471, "Inadequate Thread Engagement Concerns On Bolted-Flanged Connections," dated August 15, 2000.

Inspectors reviewed WO 00-007806 and noted that maintenance personnel repaired the flange in accordance with GMI-0021, "General Torquing," Rev. 2. GMI-0021, Rev. 2, section 5.3, "Installation Requirements," required that all bolts/studs shall have full thread engagement through the nuts. Attachment 1 of WO 00-007806, "Bolting Torque Data Sheet," included a signed signature block constituting "acceptance of above." The item immediately above the signed signature block was "proper thread engagement." Inspectors noted that there were no entries in the WO to account for or document remaining inadequate thread engagement issues on this flange.

Inspectors reviewed GMI-0021, Rev. 8, which was the revision in effect on April 25, 2005, when the additional thread issues were discovered. GMI-0021, Rev. 8, defined full or proper thread engagement as "End of bolt or stud shall be at least flush with the face of the nut... This is a minimum. Other documents may require additional length or projection beyond the face of the nut." Inspectors concluded that the licensee standard for thread engagement was consistent over the time period from flange repair until inspectors identified the issue.

Therefore, based on the licensee provided information that WO 00-007806 was the most recent maintenance activity on the RHR 'B'/'C' waterleg pump discharge flange, inspectors concluded that, at the time of flange repair, the licensee failed to identify the inadequate thread engagement of two additional fasteners on the flange. The licensee also failed to identify the issue on the initial system walkdown pursuant to the investigation for the Category 1 CR concerning inadequate thread engagement. Additionally, the licensee failed to identify the condition in the time period from after the repair was completed, on August 22, 2000, until the inspectors identified the issue on April 25, 2005.

Analysis: The inspectors determined that the licensee's failure to identify the inadequate thread engagement on a safety-related system, a condition adverse to quality, was more than minor because it could reasonably be a precursor to a more significant event. The failure to identify and correct inadequate thread engagement on bolted connections can allow a condition to exist for premature failure and leakage from the connection. Additionally, the finding was associated with the reactor safety mitigating systems cornerstone and affected the cornerstone's objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Failure to identify and correct non-conforming conditions on safety-related equipment degrades the reliability of the system to perform its safety function. The primary cause of this finding was related to the cross-cutting area of Problem Identification and Resolution in that licensee personnel failed to identify and correct the inadequate thread engagement on the RHR 'B'/'C' waterleg pump discharge flange despite multiple opportunities to identify the condition.

The inspectors reviewed IMC 0609, "Significance Determination Process (SDP)," dated March 21, 2003, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations," dated December 1, 2004 and Appendix G, "Shutdown Operations Significance Determination Process," dated February 28, 2005. The inspectors determined that 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 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, licensee personnel failed to identify and correct a condition of inadequate thread engagement on the RHR 'B'/'C' waterleg pump discharge flange. Because of the very low safety significance and because the issue has been entered into the licensee’s corrective action program (CR 05-03800), the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000440/2005006-02)**

1R05 Fire Protection (71111.05AQ)

.1 Walkdown of Selected Fire Zones/Areas

a. Inspection Scope

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

- fire zone CC-6, control complex heating ventilation and air conditioning (HVAC) system trains 'A' and 'B', on April 12, 2005;
- fire zone CC-1, control complex emergency closed cooling 'A' and 'B', on April 14, 2005;
- fire zone 1DG-1b, Unit 1 - Division 3 diesel generator building, on April 30, 2005;
- fire zone 0EW-1a, ESW Pump House, on May 3, 2005;
- fire zone 0IB-4, Intermediate Building, on May 16, 2005;
- fire zone 0IB-5, Intermediate Building, on May 20, 2005;
- fire zones 1CC-5a and 2CC-5a, Unit 1 and Unit 2 Control Rooms, on June 15, 2005;
- fire zone 1CC-3d, Unit 1 - Remote Shutdown Panel Room, on June 16, 2005; and
- fire zone 0IB-2, Intermediate Building, on June 22, 2005.

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 determine whether they were installed at their designated locations, were in satisfactory physical condition, and were unobstructed. The inspectors also evaluated the physical location and condition of fire detection devices. Additionally, passive features such as fire doors, fire dampers, and mechanical and electrical penetration seals were inspected to determine whether they were in good physical condition. The documents listed 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 vehicle fire in the Protected Area on June 30, 2005. 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, 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. This constituted one annual sample.

b. Findings

No findings of significance were identified

1R07 Heat Sink Performance (71111.07B)

Biennial Review of Heat Sink Performance

a. Inspection Scope

The inspectors reviewed the performance of the RHR heat exchangers A and B and the Division 3 EDG heat exchanger (a total of three heat exchangers). These heat exchangers were chosen for review based on their high-risk assessment worth in the licensee's probabilistic safety analysis. This review resulted in the completion of three inspection samples. The inspection objectives were to review the heat exchanger performance testing by identifying any potential testing deficiencies and heat sink problems which could increase risk, and determining whether the licensee has identified and resolved heat sink related problems that could result in initiating events or affect mitigating systems.

These objectives were accomplished by interfacing with the licensee staff, a system walkdown and the review of design basis calculations and acceptance criteria. Performance tests and inspections, including related calculations, procedures, instrument calibrations, assumptions, uncertainty analyses and the trending for each heat exchanger were reviewed and independent calculations were performed. The inspectors also verified that the test and/or inspection methodology was consistent with accepted industry and scientific practices, based on review of heat transfer texts and an Electrical Power Research Institute standard (EPRI NP-7552, "Heat Exchanger Performance Monitoring Guidelines"). The inspectors reviewed chemical treatment procedures, ultrasonic tests, biotic fouling, measures and methods to control macrofouling and ensure adequate heat transfer. The inspectors verified that conditions and operation of the equipment were consistent with design assumptions and that the licensee's actions to evaluate water hammer were appropriate. The inspectors evaluated the measures applied by the licensee to assure the performance of the ultimate heat sink. The inspectors reviewed performance tests for pumps in the ESW system. The inspectors evaluated the licensee’s corrective action program to determine whether significant heat exchanger and ultimate heat sink problems have been adequately addressed.

The documents that were reviewed are included at the end of the report.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

On May 17, 2005, 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 determine whether the training staff had observed important performance deficiencies and specified appropriate remedial actions. The inspectors’ review constituted one inspection sample.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

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

- the control complex chilled water system;
- the nuclear fuel system; and
- the digital feedwater control system.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors reviewed the licensee's evaluation of plant risk, scheduling, configuration control, and performance of maintenance associated with planned and emergent work activities to determine whether scheduled and emergent work activities were adequately managed in accordance with 10 CFR 50.65(a)(4). In particular, the inspectors reviewed the licensee's program for conducting maintenance risk assessments to determine whether the licensee's planning, risk management tools, and the assessment and management of on-line and shutdown risk were adequate. The inspectors also reviewed licensee actions to address increased on-line and shutdown risk when equipment was out of service for maintenance, such as establishing compensatory actions, minimizing the duration of the activity, obtaining appropriate management approval, and informing appropriate plant staff, to determine whether the actions were accomplished when on-line and shutdown risk were increased due to maintenance on risk-significant SSCs. The following five assessments and/or activities (samples) were reviewed:

- the licensee's preparations for an electrical distribution panel (F1F14) outage on April 4, 2005;
- the licensee's shutdown safety assessment and control of the transition from Division 2 to Division 1 divisional testing during the week of April 11, 2005;
- the licensee's shutdown safety assessment, control of emergent relay issues, and transition to on-line risk management during the period of April 29, 2005, through May 1, 2005;
- the licensee's control and risk assessment during repair of a nuclear instrument power supply failure that impacted control rod motion ability and repair of a steam bypass valve controller power supply during the week of May 16, 2005; and
- the licensee's maintenance risk assessment and work execution associated with a Division 3 outage during the week of May 30, 2005.

b. Findings

Introduction: A finding of very low safety significance and a violation of 10 CFR 50.65(a)(4) was self-revealed during preparation for an electrical distribution panel F1F14 outage on April 5, 2005, while the reactor was shutdown. Specifically, the licensee failed to identify the impact of planned breaker manipulation on the FPCC system that was the primary method of decay heat removal at the time of the event.

Description: On April 4, 2005, the licensee was preparing for an electrical distribution panel F1F14 outage. The reactor was in Mode 5, shutdown, with the refueling cavity flooded. The FPCC system was providing decay heat removal for the reactor cavity pool and the spent fuel pool. The NCC system was providing cooling water to the FPCC system heat exchangers via emergency closed cooling (ECC) valves.

During planned breaker manipulations, the K-1-D electrical bus was de-energized which de-energized the Fuel Pool Filter Demineralizer (FPFD) control panel, H51-P173. As a result, the demineralizer flow control valves shut. The valve repositioning reduced FPCC flow to the reactor pool from 720 gpm to 520 gpm and flow to the spent fuel pool from 700 gpm to 520 gpm. Numerous alarms were received in the control room. Control room personnel assessed the transient and within 30 minutes opened the FPCC FPFD bypass valve to restore proper flow to the reactor pool and spent fuel pool.

The licensee's investigation of the event identified that although Plant Data Book (PDB)-H0030, "K-1-D Load List," Rev. 0, identified the FPFD control panel as a K-1-D load and identified affected flow transmitters, the PDB did not explicitly discuss the effect of the loss of power to the flow transmitters. As demonstrated by the April 4, 2005, transient, the effect of loss of power to the flow transmitters was a loss of signal to the demineralizer flow control valves which resulted in the valve closure. As a result, the FPCC demineralizer was isolated and FPCC flow to the reactor cavity pool and spent fuel pool was reduced until operator action was taken to open the demineralizer bypass valve and restore flow.

The inspectors reviewed the licensee's investigation and concluded that although the PDB did not identify the effect of the flow transmitters on flow control valves, the licensee should have been able to determine the effect. As such, the inspectors concluded the licensee inadequately assessed risk associated with the proposed maintenance activity and adversely affected the key shutdown safety function of decay heat removal. The inspectors also noted that Nuclear Operating Procedure (NOP)-OP-1005, "Shutdown Safety," Rev. 8, required development of a summary schedule to "show train/division and key shutdown safety function system outages, electrical bus and switch-yard work, and containment closure status" and an outage schedule that "provides Defense-in-Depth and implements the requirements for key shutdown safety function availability." The inspectors considered understanding the effects of the electrical bus outages to be an implicit requirement of NOP-OP-1005.

Analysis: The inspectors determined that the failure to identify the effect of de-energizing the K-1-D bus on the decay heat removal key shutdown safety function was a performance deficiency warranting significance evaluation. The inspectors concluded that the finding was greater than minor in accordance with IMC 0612, "Power

Reactor Inspection Reports," Appendix B, "Issue Disposition Screening," dated May 19, 2005. The failure to adequately assess the consequences of proposed maintenance activities adversely affected a protected train of equipment providing the key shutdown safety function of decay heat removal. The finding was associated with the reactor safety initiating events cornerstone attribute of configuration control, and it affected the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown operations in that it adversely affected the FPCC decay heat removal function. The primary cause of this finding was related to the cross-cutting area of Human Performance in that licensee personnel failed to properly assess the impact of a planned maintenance activity on a key shutdown safety function.

The inspectors reviewed IMC 0609, "Significance Determination Process (SDP)," dated March 21, 2003, Appendix G, "Shutdown Operations Significance Determination Process," dated February 28, 2005. In consultation with the Region III senior risk analyst (SRA), the inspectors determined that the event was of very low safety significance due to the plant being in "Plant Operational State" 3, as defined in IMC 0609, Appendix G. The inspectors also noted that the licensee restored decay heat removal promptly, the estimated time-to-boil for the reactor pool and spent fuel pool was greater than a day, and other decay heat removal systems remained available.

Enforcement: In accordance with 10 CFR 50.65(a)(4), the licensee is required to assess and manage the increase in risk that may result from proposed maintenance activities. Contrary to this requirement, the licensee failed to properly assess the impact of the F1F14 maintenance activity on the FPCC system while the system was the primary method of decay heat removal. This adversely affected a protected train of equipment providing the key shutdown safety function of decay heat removal. Because of the very low safety significance and because the issue has been entered into the licensee's corrective action program (CR 05-03026 and CR 05-04335), the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000440/2005006-03)**

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

.1 Aborted Reactor Start-up Due to Erratic Level Indication

a. Inspection Scope

On May 1, 2005, while in Mode 2 and withdrawing rods to criticality, the licensee observed erratic reactor level instrument indication on instruments associated with the 'A' reference leg. Operators inserted rods and then later entered Mode 4 in order to comply with TS. Inspectors reviewed the licensee's immediate and supplemental actions. Specifically, the inspectors determined that the licensee's actions were consistent with TS and operating instructions. This review constituted the first of four samples for this inspection procedure.

b. Findings

No findings of significance were identified.

.2 Digital Feedwater Testing

a. Inspection Scope

From May 4, 2005, through May 12, 2005, the inspectors observed licensee digital feedwater system testing and tuning. The inspectors observed infrequently performed test or evolution briefings, pre-shift briefings, and reactivity control briefings to determine whether the briefings met criteria specified in the Perry Operations Section Expectations Handbook and Perry Administrative Procedure (PAP)-1121, "Conduct of Infrequently Performed Tests or Evolutions," Rev. 2. Additionally, the inspectors observed test performance to determine whether procedure use, crew communications, and coordination of activities between work groups similarly met established station expectations and standards. This review constituted the second of four samples for this inspection procedure.

b. Findings

No findings of significance were identified.

.3 Power Ascension and Synchronization to the Grid

a. Inspection Scope

On May 6, 2005, the licensee synchronized the turbine generator to the grid. The licensee performed a series of control rod line adjustments and achieved 100 percent power on May 16, 2005. Inspectors observed and reviewed licensee actions and control room activities associated with the power ascension. Inspectors determined whether the licensee's actions were consistent with TS and operating instructions. This review constituted the third of four samples for this inspection procedure.

b. Findings

No findings of significance were identified.

.4 Indication of Fire Main Underground Leak

a. Inspection Scope

On May 9, 2005, the licensee entered an off-normal instruction (ONI) procedure, ONI-ZZZ-6, "Leak in Underground Piping," Rev. 2, after observing indications of a ground water leak near the ESW pump house. The licensee identified the potential leak source as fire main piping. Inspectors observed licensee actions and control room activities in response to the underground leak. Inspectors determined whether the licensee's actions were consistent with licensee procedures. This review constituted the fourth of four samples for this inspection procedure.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (OE) (71111.15)

a. Inspection Scope

The inspectors selected 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 TS and Updated Safety Analysis Report (USAR) to the licensee's evaluations, to determine whether the components or systems were operable. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures were in place, would work as intended, and were properly controlled. Additionally, the inspectors determined, where appropriate, compliance with bounding limitations associated with the evaluations. The inspectors reviewed the following four issues (samples):

- an OE associated with the effect of a design basis tornado on ESW pumphouse ventilation to take into consideration postulated failure of the Unit 2 ventilation dampers, dated March 31, 2005;
- an OE associated with the inadequate thread engagement of fasteners on the RHR 'B'/'C' waterleg pump discharge flange, dated April 26, 2005;
- an OE associated with motor control center, switchgear, and miscellaneous electrical equipment areas' HVAC systems following identification of a concern regarding compliance with NRC Bulletin 80-06, dated April 24, 2005; and
- an OE associated with the Division 1 EDG output breaker that was discovered to be past its ten year refurbishment cycle, dated May 13, 2005.

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (OWAs) (71111.16)

a. Inspection Scope

During the week ending June 13, 2005, the inspectors performed a semiannual review of the cumulative effects of OWAs for a total of one sample. The list of open OWAs was reviewed to identify any potential effect on the functionality of mitigating systems. Inspection activities included, but were not limited to, a review of the cumulative effects of the OWA on the availability and the potential for improper operation of the system, for potential impacts on multiple systems, and on the ability of operators to respond to plant transients or accidents. Additionally, the inspectors accompanied plant operators on routine rounds to discuss the effect of active OWAs with the operators and observe any actions or conditions which should be considered as possible OWAs.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17)

a. Inspection Scope

The inspectors reviewed the design change package for installation of a reactor core isolation cooling (RCIC) head spray line pressure gage. The inspectors reviewed the engineering change package, 10 CFR 50.59 safety evaluation, and the design interface evaluations relative to the Perry licensing basis. Finally, the inspectors walked down the modification to determine whether it was installed per design documents. This review constituted one sample.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (PMT) (71111.19)

a. Inspection Scope

The inspectors evaluated the following 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 TS, 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 whether the licensee was identifying problems and entering them in the corrective action program. The specific procedures and CRs reviewed are listed in the attached List of Documents Reviewed. The following seven PMT samples were reviewed:

- Division 2 EDG governor testing and calibration on April 14, 2005;
- control complex chilled water system chiller 'A' breaker and chiller performance testing conducted April 17, 2005;
- testing of the HPCS injection valve on April 26, 2005, following electrical maintenance activities;
- testing of the motor feedpump minimum flow control valve following troubleshooting on May 4, 2005;
- testing of the P-680 panel annunciators following troubleshooting and repair on June 14, 2005;
- testing of the control rod drive pump ‘B’ breaker following repair on June 22, 2005; and
- testing of the motor fire pump following repair on June 28, 2005.

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

a. Inspection Scope

The inspectors observed work activities associated with RFO10 which began on February 22, 2005, continued through the first quarter 2005 inspection period, and concluded on May 6, 2005. The inspectors' activities during the second quarter 2005 inspection period are considered a continuation of the inspection sample credited to the first quarter of 2005.

The inspectors assessed the adequacy of outage-related activities, including implementation of risk management, preparation of contingency plans for loss of key safety functions, conformance to approved site procedures, and compliance with TS requirements. The following major activities were observed or performed:

- During the week of April 11, 2005, the inspectors reviewed the licensee’s restart readiness process relative to the procedural requirements specified in NOBP-OM-4010, “Restart Readiness For Plant Outages,” Rev. 2. Inspectors reviewed select licensee restart readiness activities to determine whether issues were appropriately identified as restart restraints and that these restart restraint issues were appropriately resolved. Additionally, the inspectors attended the licensee’s restart readiness meeting conducted April 24, 2005.

- On April 26, 2005, and April 30, 2005, the inspectors conducted drywell closeout tours to determine whether material condition supported plant restart.

- On May 3, 2005, the inspectors observed the licensee’s reactor startup and initial criticality. The inspectors observed shift briefings, operator performance, shift management coordination of plant activities, and conformance with TS requirements including heat-up limitations and mode change requirements.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors observed surveillance testing or reviewed test data for risk-significant systems or components to assess compliance with TS; 10 CFR 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 samples assessed were:

- aborted Division 2 LOOP testing on April 8, 2005;
- Division 2 LOOP testing on April 13, 2005;
- Division 3 EDG loss of coolant accident electrical trip bypass and differential relay trip tests; auto-start and engine trip bypass test on emergency core cooling system actuation; and LOOP testing conducted April 20, 2005, and April 21, 2005;
- reactor pressure vessel system leak tests conducted during the week of April 18, 2005;
- RHR 'A' pump and valve operability test on May 18, 2005;
- off-gas post-treatment radiation monitor channel 'A' functional tests on June 13, 2005; and
- standby liquid control ‘B’ pump and valve operability tests on June 21, 2005.

b. Findings

.1 Inadvertent Loss of Decay Heat Removal

Introduction: A finding of very low safety significance and a violation of TS 5.4 was self-revealed when licensee personnel inadvertently isolated decay heat removal from the reactor pool and the spent fuel pool on April 5, 2005. Personnel conducting LOOP test preparations, governed by procedure SVI-R43-T1338, “Division 2 Standby Diesel Generator Loss of Offsite Power (LOOP) Test,” Rev. 7, performed a procedure step out of sequence. This resulted in the isolation of cooling water to the FPCC system heat exchangers which were aligned to remove decay heat from the reactor pool and the spent fuel pool. The licensee failed to follow procedure SVI-R43-T1338 as written.

Description: On April 5, 2005, the licensee was preparing for Division 2 LOOP testing and the reactor was in Mode 5, shutdown, with the refueling cavity flooded. The FPCC system was providing decay heat removal for the reactor cavity pool and the spent fuel pool. The NCC system was providing cooling water to the FPCC system heat exchangers via ECC valves. A senior reactor operator (SRO) was serving as test director and was providing overall supervision for the LOOP testing preparation. A reactor operator (RO) was serving as test team leader and was coordinating the performance of prerequisite steps in SVI-R43-T1338, the LOOP test procedure. Under the direction of the RO, operators and technicians were in the field performing the procedure steps to set up plant systems for the Division 2 LOOP test.

The LOOP test procedure’s purpose was to test plant system response to a simulated LOOP signal on Division 2. The preferred method of testing system response included verification of physical operation of components tested. The alternate method of testing system response included verification of system control circuit response on a LOOP signal. Because the ECC valves supplying NCC cooling water to the FPCC system were desired to be open for decay heat removal, the licensee decided to test the ECC valves using the alternate method. In order to test the ECC valves using the alternate method, the test procedure, SVI-R43-T1338, required technicians to obtain resistance readings across control circuit contacts for the ECC valves. Prior to obtaining resistance readings on the control circuits, the procedure required the removal of power to the associated valve.

The test procedure contained a note that allowed many prerequisite test lineup steps to be performed in any order. However, it did not contain a note allowing sub-steps to be performed in any order.

The test lead RO was in the control room for the performance of SVI-R43-T1338 step 5.1.2.12 which affected the ECC valves to the FPCC system. The RO received a call from technicians in the field that they had, about two hours earlier, taken resistance readings on the ECC valves per sub-steps 5.1.2.12.b.3 and 5.1.2.12.d.3. The RO noted that he had not yet given the order for operators to down-power the ECC valves. He noted that the resistance readings were performed out of sub-step sequence within the procedure step. During an interview with inspectors, the RO indicated he understood that valves were to be down-powered prior to electrical checks in order to prevent isolation of decay heat removal. However, he indicated he did not recognize how the resistance checks had the potential to re-position the valves and therefore made the decision to continue with the uncompleted sub-steps within step 5.1.2.12 even though a procedure sub-step had been performed out of sequence. The RO gave an in-field operator the order to de-energize the ECC valves. The RO had performed a system walkdown approximately a day before commencement of the test procedure and had verified the lineup of the ECC valves affecting the FPCC system. However, when he found out that the electrical checks had been performed out-of-sequence, he was not in the immediate vicinity of the ECC valve position indications in the control room and he failed to verify ECC valve position prior to ordering valve power removed. As power was removed from the ECC valves, the valve position indication in the control room was lost for the de-energized valve.

On instruction from the test RO, the operator in the field de-energized the P42-F440 valve, which was the FPCC heat exchanger isolation for both FPCC heat exchangers. The shift manager noted that ECC valve down-powering had started and went to the FPCC panel to observe. The shift manager noted that the FPCC valve lineup did not appear correct in that the P42-F380A valve, which supplied NCC cooling to FPCC system heat exchanger 'A,' indicated closed. The P42-F380A closed valve indication was still present at the FPCC panel in the control room; however, the P42-F440 valve position indication was not present on the panel since this valve had already been down-powered. The shift manager discussed the condition with the unit supervisor and power was restored to P42-F440. When power was restored, P42-F440 indicated closed. Both valve P42-F440 and valve P42-F380A were re-opened and decay heat removal to the reactor pool and the spent fuel pool was restored. The valves had been shut for approximately two hours.

Investigation by the licensee revealed that the resistance checks on the ECC valve circuitry while energized had caused two of the valves affecting the FPCC system, valves P42-F440 and P42-F380A, to close while other valves remained unaffected. The instrument used to perform the resistance checks was a Simpson 260 meter. The loss of decay heat removal for approximately two hours resulted in approximately a 1 EF rise in temperature for the reactor pool and the spent fuel pool.

Analysis: The inspectors determined that the failure to follow procedures as written was a performance deficiency warranting significance evaluation. The inspectors concluded that the finding was greater than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Disposition Screening," dated June 20, 2003. The failure to follow procedures resulted in a loss of cooling for the reactor pool and spent fuel pool for approximately two hours. The finding was associated with the reactor safety initiating events cornerstone attribute of configuration control, and it affected the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown operations in that it resulted in loss of FPCC decay heat removal function. The finding affected the cross-cutting area of Human Performance because licensee personnel performed procedure steps out of sequence, continued to perform the procedure without adequate review once the error was noted, and failed to recognize the potential for valve closure due to the electrical checks on energized control circuitry.

The inspectors reviewed IMC 0609, "Significance Determination Process (SDP)," dated May 19, 2005, Appendix G, "Shutdown Operations Significance Determination Process," dated February 28, 2005. In consultation with the Region III SRA, the inspectors determined that the event was of very low safety significance due to the plant being in "Plant Operational State" 3, as defined in IMC 0609, Appendix G. The inspectors also noted the licensee restored decay heat removal promptly, the estimated time to boil for the reactor pool and spent fuel pool was greater than a day, and other decay heat removal systems remained available.

Enforcement: Technical Specification 5.4 required implementation of the applicable procedures recommended in Regulatory Guide 1.33 Rev. 2, Appendix A. Regulatory Guide 1.33 Appendix A, Part 8, recommended procedures for surveillance tests. Contrary to this requirement, the licensee failed to follow procedures as written during the Division 2 LOOP surveillance test. This resulted in loss of decay heat removal for approximately two hours. Because of the very low safety significance and because the issue has been entered into the licensee's corrective action program (CR 05-03054), the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000440/2005006-04)**

.2 Failure to Follow Procedures Affecting Safety-Related Division 3 Breakers

Introduction: A finding of very low safety significance and a violation of TS 5.4 was self-revealed on April 21, 2005. Technicians failed to follow the procedure for Division 3 LOOP testing and installed a jumper in the wrong safety-related breaker cubicle.

Description: On April 21, 2005, the licensee was performing Division 3 LOOP testing in accordance with procedure SVI-E22-T1339, "Division 3 HPCS Diesel Generator Loss Of Off-Site Power Test," Rev 3. The plant was in Mode 5, shutdown, at the time of the event. Under direction of control room operators, two technicians were to perform procedure steps in the Division 3 switchgear room.

The licensee personnel were in the process of performing SVI-E22-T1339 procedure section 5.1.2, “Surveillance Test, HPCS Diesel Generator Loss of Off-Site Power.” The preferred source breaker for HPCS was closed and aligned to the HPCS EH13 bus. Procedure step 5.1.2.2 contained sub-steps necessary to close the HPCS alternate preferred source breaker EH1302. Procedure sub-steps 5.1.2.2.a and 5.1.2.2.b directed technicians to place the alternate preferred source breaker, EH1302, into the test position and to tie down the cell switch of EH1302. Procedure sub-step 5.1.2.2.c directed technicians to install a jumper between two terminal points in breaker cubicle EH1303. Breaker EH1303 was the preferred source breaker for HPCS. The jumper would have bypassed an interlock in the EH1303 breaker in order to allow closure of the EH1302 breaker. However, the technicians failed to follow procedure sub-step 5.1.2.2.c as written and installed the jumper in the EH1302 breaker cubicle instead. Then, per procedure sub-steps 5.1.2.2.d and 5.1.2.2.e, operators in the control room repositioned the synchroscope and took the EH1302 breaker switch to the close position. Breaker EH1302 failed to close as operators expected. A subsequent walkdown of the breaker cubicles by licensee personnel revealed that the jumper was installed in cubicle EH1302 instead of cubicle EH1303.

The licensee evaluated the impact of the jumper installation in cubicle EH1302 and determined that the jumper error did not adversely affect plant equipment. EH1303 was already in the closed position. EH1302 was in the test position. The jumper was removed from cubicle EH1302.

Inspectors noted that the procedure SVI-E22-T1339 step 5.1.2.2.c required independent verification by the technicians and that it required the initials of each technician to indicate that independent verification of the procedure step had been performed. The inspectors were informed that, contrary to this requirement, the technicians utilized a concurrent method of verification. The inspectors were also informed that no management oversight was present in the field.

Analysis: The inspectors determined that the failure to follow procedures affecting safety-related equipment was a performance deficiency warranting further evaluation. The inspectors determined that the issue was more than minor because it could reasonably be viewed as a precursor to a more significant event. Additionally, if left uncorrected, the failure to follow procedures affecting safety-related equipment could become a more significant safety concern. The primary cause of this finding was related to the cross-cutting issue of Human Performance because a personnel error was the primary cause of the event.

Using IMC 0609, Appendix G, “Shutdown Operations Significance Determination Process,” the inspectors reviewed the finding against Attachment 1 for Phase 1 screening. Because the finding did not result in a loss of safety function, the inspectors determined that the finding was not suitable for quantitative assessment and concluded that the finding was of very low safety significance.

Enforcement: The performance deficiency was the failure to follow procedures that were required for plant operation. Technical Specification 5.4 requires implementation of procedures recommended by Regulatory Guide 1.33, Appendix A. Regulatory Guide 1.33, Appendix A, Part 8, recommended procedures for surveillance tests. The surveillance test SVI-E22-T1339, step 5.1.2.2.c stated, “In Cubicle EH1303 install jumper between terminal points AA-14 and AA-19.” Contrary to the requirements of TS 5.4, SVI-E22-T1339, step 5.1.2.2.c was improperly performed in that the jumper was installed in breaker EH1302 instead of breaker EH1303. Because of the very low safety significance and because the issue has been entered into the licensee’s corrective action program (CR 05-00871) it is being treated as an NCV, consistent with Section VI.A of the NRC's Enforcement Policy. (**NCV 05000440/2005006-05**)

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

The inspectors observed activities in the technical support center, the emergency operations facility, and operations support center during an emergency preparedness drill conducted on June 20, 2005. 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. This constituted one sample.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

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 determine whether they were being entered into the licensee’s corrective action program at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed.

b. Findings

No findings of significance were identified.

.2 Annual Sample Review - Inadequate Thread Engagement

c. Inspection Scope

The inspectors identified inadequate thread engagement affecting a discharge flange for the RHR 'B'/'C' waterleg pump as described in section 1R04 of this report. Because inspectors had noted similar problems on other plant equipment and because inspectors were aware that inadequate thread engagement on plant equipment was a recurring issue, inspectors selected the issue for in-depth review. Inspectors reviewed CRs associated with inadequate thread engagement to determine whether the full extent of the issue was identified, whether an appropriate evaluation was performed, and whether appropriate corrective actions were specified and prioritized. The inspectors evaluated the CRs against the requirements of the licensee's corrective action program as delineated in NOP-LP-2001, "Condition Report Process," Rev. 10, and 10 CFR 50, Appendix B.

This review constituted the first of two annual samples for this inspection procedure.

d. Findings and Observations

A finding and associated NCV related to inadequate problem identification and resolution for improper thread engagement is documented in section 1R04 of this report.

The inspectors noted that despite a root cause investigation (CR 00-2471) and corrective actions associated with thread engagement problems identified on plant equipment in the year 2000, and despite numerous subsequent apparent cause CRs and corrective actions addressing the issue, inadequate thread engagement problems on plant equipment continue to be identified. A search of the licensee database for CRs subsequent to CR 00-2471 and related to inadequate thread engagement revealed approximately 100 entries. Approximately 27 of these were classified "CA," indicating an apparent cause investigation would have been done. Furthermore, from March through May of 2005, during routine plant walk-through and inspection, inspectors identified several instances of inadequate thread engagement affecting plant equipment. These issues were subsequently documented in CRs 05-04411, 05-03800, 05-03675, 05-03270, 05-03269, and 05-02616.

During the review of the CR history, the inspectors noted that corrective actions to address inadequate thread engagement were often narrow in focus and extent of condition review and actions to prevent recurrence of inadequate thread engagement were not effective in that numerous examples continued to be identified. An example of the narrow focus is described in section 1R04 of this report where the licensee identified inadequate thread engagement on the RHR 'B'/'C' waterleg pump flange, repaired one nut on the flange and closed out the WO and corrective action with two other inadequately engaged nuts remaining on the same flange.

.3 Annual Sample Review - Failure to Control Low Pressure Test Gages

e. Inspection Scope

The inspectors selected CR 05-04112 for detailed review. This CR was associated with the licensee's failure to remove temporary test gages from the RHR system and the leak detection system (LDS) associated with the RWCU system following PMT activities. The gages were not identified until after system pressurization and reactor start-up. The CR was reviewed to ensure that the full extent of the issues were identified, an appropriate evaluation was performed, and appropriate corrective actions were specified and prioritized. The inspectors evaluated the reports against the requirements of the licensee's CAP as delineated in NOP-LP-2001, "Condition Report Process," Rev. 10 and 10 CFR 50, Appendix B. This review constituted the second of two annual samples for this inspection procedure.

f. Findings and Observations

Introduction: A finding of very low safety significance and a violation of 10 CFR 50, Appendix B, Criterion XII, "Control of Measuring and Test Equipment" was self-revealed when a non-licensed operator in the RHR 'A' room noted a temporary pressure gage was not properly removed from the RHR system following PMT activities. A subsequent extent of condition review by the licensee determined that a second temporary gage associated with the same maintenance WO had not been removed from a LDS flow instrument associated with the RWCU system. The inspectors considered this to be a self-revealed finding in that the licensee's maintenance procedure close-out review and required pre-startup system walkdowns did not identify the gages as being installed until after they were exposed to plant conditions outside of their ratings.

Description: On May 6, 2005, with the plant in Mode 2, reactor power at 9 percent, and the reactor at 940 psig, a non-licensed operator in the RHR 'A' room noted a temporary pressure gage installed on the tailpiece of RHR test connection isolation valve 1E12-F059B. The licensee performed an extent of condition review and determined that an identical pressure gage was also connected to the low pressure test connection of the LDS differential pressure detector 1E31-N077B.

The LDS detector provides an indication of RWCU return flow to the feedwater system by measuring differential pressure across a flow element in the return line. This flow signal is sent as an input to the LDS for the RWCU differential flow-high circuit. Specifically, inlet flow to the RWCU system is measured and compared to system total outlet flow. If inlet flow exceeds total outlet flow by greater than approximately 59 gpm, a 10 minute timer is initiated. If the abnormal differential flow signal persists until the timer has timed out, the RWCU system will isolate. This isolation is provided for protection for a cold piping leg break where differential and area temperature isolations in the RWCU system would not provide protection to isolate the piping.

When the pressure gage was installed at the low pressure test connection of 1E31-N077B on April 30, 2005, in accordance with Perry Problem Solving Plan associated with WO 200147914, the equalizing valve 1E31-N077B-E was opened, which rendered the LDS differential pressure detector inoperable. At the time, the plant was in Mode 4 (Cold Shutdown) and the RWCU differential flow-high circuit was not required to be operable. Contrary to TS 3.3.6.1 Table 1, the licensee entered Mode 2 (Reactor Startup) on May 5, 2005, with the RWCU return to feedwater flow input to the RWCU differential flow-high circuit inoperable because the equalizing valve 1E31-NO77B-E remained open. Upon discovery of the test gages, the licensee proceeded to remove the gages and restore the operability of the RWCU return line flow detector within the time permitted by TS.

Analysis: The inspectors determined that erroneously leaving test gages installed after testing was completed and plant startup commenced was a performance deficiency warranting significance evaluation. The inspectors concluded that the finding was greater than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Disposition Screening," dated May 19, 2005. The failure to control test equipment while changing plant conditions outside of the ratings of the equipment, if left uncorrected, could become a more significant safety concern. The finding was associated with the barrier integrity attribute of configuration control, as well as human performance, and affected the cornerstone objective of providing reasonable assurance that physical barriers protect the public from radionuclide releases caused by accidents or events. The finding affected the cross-cutting area of Human Performance because operators failed to adequately control test equipment in the RWCU and RHR systems.

The inspectors reviewed IMC 0609, "Significance Determination Process (SDP)," dated May 19, 2005, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations," dated December 1, 2004, and Appendix G, "Shutdown Operations Significance Determination Process," dated February 28, 2005. The inspectors determined that the barrier integrity cornerstone was affected because the containment barrier associated with the Auxiliary Building was degraded in that the LDS associated with the RWCU system was left inoperable due to a failure to properly maintain configuration control following maintenance. Because the finding only represented a degradation in the radiological barrier function of the Auxiliary Building and the finding did not represent an actual open pathway in the physical integrity of the reactor containment or involve an actual reduction in defense-in-depth for the atmospheric pressure control or hydrogen control functions of the reactor containment, the inspectors determined the finding to be of very low safety significance.

Enforcement: Appendix B of 10 CFR 50, Criterion XII, "Control of Measuring and Test Equipment," requires, in part, that measures shall be established to assure that tools, gages, instruments, and other measuring and test devices used in activities affecting quality be properly controlled. Contrary to this requirement, the licensee failed to implement appropriate procedures during PMT of the G33-F052B check valve, thereby losing control of installed test equipment.

Because of the very low safety significance and because the issue has been entered into the licensee's corrective action program (CR 05-04112), the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy.
(NCV 05000440/2005006-06)

.4 Semi-Annual Trend Review

a. The inspectors reviewed system health reports, self-assessments, quality assurance assessment reports, performance improvement initiatives and CRs to identify any trends that had not been adequately evaluated or addressed by proposed corrective actions.

b . Findings

No findings of significance were identified. However, the inspectors noted that the licensee acknowledged a negative performance trend in the area of human performance including procedural adherence. The licensee implemented corrective actions to address the issue. Corrective actions included additional training, additional human performance measures and processes, and work stand-downs. Inspectors noted that numerous human performance issues, including procedural adherence, were identified during the inspection period despite licensee corrective action to address the issue.

4OA3 Event Followup (71153)

.1 (Closed) Licensee Event Report (LER) 50-440/2005-002-00: All Emergency Diesel Generators Declared Inoperable Due to Degraded Testable Rupture Discs (TRD).

Introduction: A finding of very low safety significance and a violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," was self-revealed when the Division 2 EDG TRD required excessive force to lift during surveillance testing on February 17, 2005. The finding was self-revealed because subsequent licensee inspection identified disc deformation. As a result, all three EDGs were declared inoperable due to common cause concerns. The root cause of this issue was determined to be an inadequate design review.

Description: Prior to May 2005 the safety-related EDG exhaust system included TRDs which were designed to open in the event the non-safety-related exhaust path became blocked or obstructed during a seismic or tornado initiated loss of off-site power event. To address long-standing deficiencies associated with the performance of EDG TRDs, the licensee took action to install a new TRD design during 2004. Specifically, the new Division 1 EDG TRD was installed in November 2004, the new Division 2 EDG TRD in October 2004, and the new Division 3 EDG TRD in April 2004.

Although the Division 3 EDG TRD had satisfactorily met surveillance lift acceptance criteria, the Division 1 and 2 EDG TRDs failed to meet the acceptance criteria in both January 2005 and February 2005. Following the January 2005 surveillance failures, the licensee conducted past operability evaluations based on as-found data and determined that although fuel oil consumption was adversely affected by the condition, the EDGs remained operable. The TRD's lift setting was adjusted to the acceptable range and the EDGs were returned to service.

On February 17, 2005, the Division 2 EDG TRD again failed to lift within acceptance criteria. As part of the licensee's problem solving plan to address the repetitive test failure, licensee inspection identified that the disc was warped. Due to potential common cause issues, the licensee declared all three EDGs inoperable and entered TS LCO 3.0.3 at 5:30 p.m. on February 17, 2005. The licensee unlatched the Division 2 EDG TRD and declared the Division 2 EDG operable at 8:11 p.m. later that same day. The operable Division 2 EDG allowed the licensee to exit TS LCO 3.0.3. The licensee subsequently unlatched the Division 1 and 3 EDG TRDs to restore operability of the respective EDG.

The licensee's root cause evaluation of the failed design modification identified that licensee engineering design personnel "did not have adequate skills and experience" to perform component level design. Examples cited to support the inadequate skills conclusion included the failure to adequately consider thermal deformation and friction factors. Additionally, the evaluation noted that testing performed to validate the design modification was less than adequate.

Prior to the completion of RFO10, the licensee implemented a design change which physically removed each TRD. The design change is discussed in NRC Supplemental IR 05000440/2005003.

<u>Analysis</u>: The inspectors determined that engineering errors that resulted in the inoperability of all three divisional EDGs was a performance deficiency warranting significance evaluation. The inspectors determined that the issue was more than minor because the finding was associated with the mitigating systems cornerstone attribute of design control and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The finding affected the cross-cutting issue of Human Performance because licensee personnel failed to perform an adequate design review.

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 that since the finding involved the loss of safety function of all three EDGs, a Phase 2 evaluation was required. The inspectors conducted a Phase 2 evaluation and determined that a Phase 3 evaluation was required.

The Region III SRA performed a qualitative Phase 3 analysis using information provided in the LER. The Division 3 EDG was assumed to be unaffected because the TRD lifted low or within the required range. The Division 1 and Division 2 EDGs were determined to be affected because the TRDs lifted higher than the setpoint range allowed. Due to the low likelihood of a seismic event or a tornado that would damage the Division 1 and Division 2 normal exhaust paths and the fact that Division 3 is assumed to be unaffected, the finding was determined to be of very low safety significance. Additionally, the RCIC system and potentially other core cooling systems would be available in these scenarios to allow for recovery of either the EDGs or recovery of offsite power. The licensee provided additional information in the LER on why it was conservative to assume complete failure of the EDGs in these scenarios. The initiating event would have to damage both divisions in a way that would block normal exhaust flow such that TRD operation would be required. Additionally, the TRD failure would have to render the EDGs non-functional. The SRA agreed that there was significant uncertainty regarding the assumption that the EDGs would be failed in all postulated seismic and tornado events due to the deficiency with the TRD operation.

<u>Enforcement:</u> Appendix B of 10 CFR Part 50, Criterion III, "Design Control," required, in part, that measures shall provide for verifying and checking the adequacy of design, such as by the performance of design reviews. Contrary to these requirements, in engineering change packages 01-5018, 04-0169, and 04-0170, the licensee failed to consider the potential for and the effect of deformation of the TRD due to heat during the design phase and then subsequently failed to adequately test the new design. Consequently, Division 1 and Division 2 EDG TRDs consistently lifted high outside the acceptance band and, in the case of the Division 2 EDG TRD, began to physically deform. As a result, all 3 EDGs were declared inoperable.

Because of the very low safety significance and because the issue has been entered into the licensee's corrective action program (CR 05-01136), the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000440/2005006-07)**

.2 Closed) Licensee Event Report (LER) 05000440/2005-001-00: Manual Reactor SCRAM Following Unexpected Reactor Recirculation Pump Trip. On January 6, 2005, both reactor recirculation pumps downshifted from fast to slow speed. The power and flow reduction placed the plant in the immediate exit region of the power-flow map. While control room operators were in the process of inserting control rods to exit the region, reactor recirculation pump 'A' tripped. Following the reactor recirculation pump trip, the reactor operator inserted a manual scram. Inspector response associated with this event was documented in NRC Integrated IR 05000440/2005002. The repetitive downshift of the reactor recirculation pumps (as documented in LER 05000440/2004-002-00) and equipment issues discussed in this LER, were reviewed and enforcement action documented in NRC Special Inspection Team Report 05000440/2005005. This LER is closed.

4OA4 Cross-Cutting Aspects of Findings

.1 A finding described in Section 1R04 of this report had, as its primary cause, a problem identification and resolution deficiency in that the licensee failed to identify and correct non-conforming conditions related to thread engagement on safety-related equipment.

.2 A finding described in Section 1R13 of this report had, as its primary cause, a human performance deficiency in that licensee personnel failed to properly assess the impact of a planned maintenance activity on a key shutdown safety function.

.3 A finding described in Section 1R22.1 of this report had, as its primary cause, a human performance deficiency in that licensee personnel performed procedure steps out of sequence, continued to perform the procedure without adequate review once the error was noted, and failed to recognize the potential for valve closure due to the electrical checks on energized control circuitry. This resulted in loss of decay heat removal for approximately two hours.

.4 A finding described in Section 1R22.2 of this report had, as its primary cause, a human performance deficiency in that technicians failed to follow the procedure for Division 3 LOOP testing and installed a jumper in the wrong safety-related breaker cubicle.

.5 A finding described in Section 4OA2.3 of this report had, as its primary cause, a human performance deficiency in that licensee personnel did not remove low pressure gages in accordance with written instructions.

.6 A finding described in Section 4OA3.1 of this report had, as its primary cause, a human performance deficiency in that the licensee failed to perform an adequate design review. Specifically, licensee design engineers failed to consider the potential for and the effect of deformation of the TRD due to heat during the design phase of the design modification process and then subsequently failed to adequately test the new design.

4OA5 Other Activities

.1 Temporary Instruction (TI) 2515/163, Operational Readiness of Offsite Power

The inspectors completed TI 2515/163, Operational Readiness of Offsite Power. Per the TI instructions, the inspectors reviewed: licensee operating procedures that the control room operators use to assure the operability of off-site power sources; licensee procedures used to ensure compliance with 10 CFR 50.65(a)(4); and licensee procedures to ensure compliance with 10 CFR 50.63. Based on the inspection, no immediate operability issues were identified. In accordance with TI 2515/163 reporting requirements, the inspectors provided the required data to the headquarters staff for further analysis.

.2 (Closed) Unresolved Item (URI) 05000440/2004013-05; Safety-System Unavailability for RHR:

As documented in NRC Integrated IR 05000440/2004013, during review of the RHR safety system unavailability data, the inspectors noted that the licensee did not include unavailable hours for RHR 'B' while the plant was shutdown for ESW ‘B’ pump repairs. During this shutdown, the licensee appropriately counted unavailability hours for RHR 'A'. However, prior to removing ESW 'B' from service, which rendered RHR 'B' inoperable and unavailable, the licensee established an Off-Normal Instruction (ONI) that would provide decay heat removal provided reactor water temperature remained below 150 EF. This method used a feed and bleed strategy that used RWCU and condensate and feed systems to use the main condenser as the heat sink. The guidance contained in Nuclear Energy Institute (NEI) 99-02, “Regulatory Assessment Indicator Guideline,” Rev. 2 allowed exclusion of RHR unavailability hours only if an NRC-approved alternate method of decay heat removal was available. Since the NRC has neither reviewed nor approved this method as an alternate decay heat removal path, the inspectors concluded these hours should be included, which would result in a White PI for RHR system unavailability. The licensee contended that any method permitted by TS was NRC-approved; and therefore, exclusion of these hours was consistent with NEI guidance. Perry TS do not list acceptable alternate methods of alternate decay heat removal; however, the basis stated that the cooling capacity of the alternate method must be demonstrated empirically or by calculation. Further, the basis stated that alternate methods include, but are not limited to, RWCU. The licensee determined the capacity of the feed and bleed method by calculation. The licensee submitted a “Frequently Asked Question” on this issue. On May 19, 2005, the NRC completed review of FAQ 391 and determined that “NRC approval means a specific method or methods described in the technical specifications.” As a result, the licensee recalculated and resubmitted RHR system unavailability. Had the PI data been properly reported in the second quarter 2004, the PI color would have been White. Failure to properly report the PI was considered a Severity Level IV Non-Cited Violation of 10 CFR 50.9. **(NCV 05000440/2005006-08)**

.3 <u>(Closed) URI 05000440/2001016-03 (formerly identified as 50-440/01-16-03); Scrams with Loss of Normal Heat Removal Reporting Criteria</u>

As documented in NRC IR 05000440/2001016, during review of the scrams with loss of normal heat removal PI data, the inspectors noted that the licensee did not include the December 15, 2001, scram. On December 15, 2001, a failure of the feedwater control system circuitry resulted in high reactor water level and generated a level 8 scram signal. The reactor feed pump turbines tripped, as designed, at Level 8 and reactor water level dropped rapidly (less than 60 seconds) to level 2 due to loss of feedwater. As documented in personnel statements after the event, there was confusion during the initial stages as to what caused the transient. A RO noted trips of both reactor feed pump turbines 'A' and 'B,' noted the motor feed pump (MFP) failed to auto start, and noted that both the red and green indicating lights for the MFP were extinguished. The unit supervisor later documented that "it was announced in the control room that we had no feed pumps." The licensee concluded that all systems functioned as designed and, as a result, there was no loss of normal heat removal. Licensee personnel, specifically, regulatory affairs, informed the inspectors that had the operators required the MFP they would have attempted to start it and it would have functioned as designed and therefore was always available. The licensee submitted a "Frequently Asked Question" on this issue. On May 19, 2005, the NRC completed review of FAQ 385 and that "the scram was not very complicated. The TDFWPs [turbine driven feedwater pumps] were readily available since the licensee had a special procedure for fast recovery and had included it as part of routine requalification program training." As such, it was determined that the December 15, 2001, scram did not count as a scram with loss of normal heat removal.

4OA6 <u>Meetings</u>

.1 <u>Exit Meeting</u>

The inspectors presented the inspection results to Mr. R. Anderson, Site Vice President and other members of licensee management at the conclusion of the inspection on June 30, 2005. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. Proprietary information was reviewed by the inspectors and returned to the licensee.

.2 <u>Interim Exit Meeting</u>

An interim exit meeting was conducted for:

- The biennial heat sink inspection results were presented to Mr. R. Anderson and other members of licensee management at the conclusion of the inspection on April 22, 2005.

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

The following violation of very low safety significance was identified by the licensee and was a violation 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 required implementation of procedures recommended in Regulatory Guide 1.33, Rev. 2, Appendix A, February 1978. Regulatory Guide 1.33, Appendix A, Section 1.c., specified that implementing procedures are required for equipment control. Contrary to these requirements, the licensee failed to adequately implement procedures for control of tornado depressurization barriers. Specifically, PAP-0911, "Control Room Boundary Integrity and Tornado Depressurization Barrier Integrity," Rev. 3 was developed to provide "the method to control inspection, testing, and repair (corrective/planned maintenance) of components associated with the control room boundary and tornado depressurization barriers." On February 16, 2005, the licensee impaired door IB-313 to route service lines through the door to support RFO activities. The licensee initiated a fire impairment, but, despite the door being labeled as a tornado depressurization barrier, the licensee failed to take actions specified in PAP-0911, Section 6.4 which included incorporating any required compensatory measures into the work plan requiring the impairment. The licensee identified the failure to follow PAP-0911 during a plant walkdown on February 28, 2005. Compensatory measures were established later that same day to restore compliance. This issue was entered in the licensee's corrective action program as CR 05-01567. The issue was determined to be of very low safety significance due to the low probability of tornados during the 12 days during which the barrier was impaired.

KEY POINTS OF CONTACT

Licensee

R. Anderson, Vice President-Nuclear
F. von Ahn, General Manager, Nuclear Power Plant Department
S. Thomas, Radiation Protection Manager
F. Kearney, Operations Manager
R. Kidder, Superintendent, Plant Operations
J. Lausberg, Manager, Regulatory Compliance
T. Lentz, Director, Nuclear Engineering
K. Meade, Regulatory Compliance Supervisor
J. Messina, Director, Performance Improvement
W. O'Malley, Maintenance Manager
R. Pikus, Generic Letter 89-13 System Engineer
K. Russell, Regulatory Affairs

Nuclear Regulatory Commision
A. M. Stone, Chief, Systems Engineering Branch
W. Macon, NRR Project Manager

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000440/2005006-01	FIN	Untimely Hot Weather Preparations (Section 1R01)
05000440/2005006-02	NCV	Failure to Identify and Correct Inadequately Threaded Bolts on RHR 'B'/'C' Waterleg Pump (Section 1R04)
05000440/2005006-03	NCV	Failure to Identify the Effect of Deenergizing Bus K-1-D on Decay Heat Removal (Section 1R13)
05000440/2005006-04	NCV	Inadvertent Loss of Decay Heat Removal (Section 1R22.1)
05000440/2005006-05	NCV	Failure to Follow Procedures Affecting Safety-Related Division 3 Breakers (Section 1R22.2)
05000440/2005006-06	NCV	Failure to Control Low Pressure Test Gages (Section 4OA2.3)
05000440/2005006-07	NCV	Failure to Perform Adequate Design Review for Testable Rupture Disk Modification (Section 4OA3.1)
05000440/2005006-08	NCV	Unreported Safety-System Unavailability for RHR (Section 4OA5.2)

Closed

05000440/2005-002-00	LER	All Emergency Diesel Generators Declared Inoperable Due to Degraded Testable Rupture Discs (Section 4OA3.1)
05000440/2005-001-00	LER	Manual Reactor SCRAM Following Unexpected Reactor Recirculation Pump Trip (Section 4OA3.2)
05000440/2004013-05	URI	Safety-System Unavailability for RHR (Section 4OA5.2)
05000440/2001016-03	URI	Scrams With Loss of Normal Heat Removal Reporting Criteria (Section 4OA5.3)

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.

1R01 Adverse Weather Protection

NOBP-WM-2301; Seasonal Readiness; Rev. 0
IOI-15; Seasonal Variations; Rev. 5
CR 02-02069; Implementation of CR 99-1886; dated June 26, 2002
CR 02-02111; SSDI - Ensuring that Future CA and OD are Properly Implemented; dated June 27, 2002
CR 02-02237; Seasonal Readiness for Summer 2002 Critique; dated July 9, 2002
CR 03-03338; RFO9 Extension Causing Seasonal Readiness Preps to be Delayed Beyond 6/1/03; dated May 18, 2003
CR 03-05724; Critique for Winter Preparations for 2002 Was Not Performed; dated October 14, 2003
CR 03-06704; Summer 2003 Seasonal Readiness Critique; dated December 19, 2003
CR 05-03742; Summer Preparation Not in Compliance with NOBP-WM-2301; dated April 24, 2005
CR 04-05920; Late Performance of Winterization Activities; dated November 16, 2004
CR 05-5052; 2004 Seasonal Readiness Critiques Not Performed as Directed by procedure; dated June 28, 2005
CR 05-05053; Winter 2005 Seasonal Critique Not Performed as Directed by Procedure; dated June 28, 2005
Summer Preparation Work List; dated May 25, 2005

1R04 Equipment Alignment

USAR Figure 9.2-4; Nuclear Closed Cooling System; Rev. 13
USAR Figure 9.2-3; Emergency Closed Cooling System; Rev. 13
VLI-P43; Nuclear Closed Cooling; Rev. 7
VLI-P42; Emergency Closed Cooling System; Rev. 10
VLI-E21; Low Pressure Core Spray System; Rev. 5

VLI-E12; Residual Heat Removal System; Rev. 5
SOI-E12; Residual Heat Removal System; Rev 23
CR 05-03800; 1E12C0003 Discharge Flange Inadequate Thread Engagement; dated April 26, 2005
CR 00-2471;Inadequate Thread Engagement Concerns on Bolted-Flanged Connections; dated August 15, 2000
Perry Nuclear Power Plant; Plant Health Report; Fourth Quarter 2004
VLI-P45; Emergency Service Water; Rev. 7
Drawing D-302-791; Emergency Service Water System; Rev. 13
Drawing D-302-792; Emergency Service Water System; Rev. 13
ISI-P45-T1104-3; ESW Sluice Gates Inflatable Seals System Functional Pressure Test; Rev. 0
SOI-P45/49; Emergency Service Water and Screen Wash Systems; Rev. 11

1R05 Fire Protection

FPI-0CC Fire Zone 1CC-6; HVAC Systems Train B; Rev. 3
FPI-0CC Fire Zone 2CC-6; HVAC Systems Train A; Rev. 3
FPI-0CC Fire Zone 0CC-1A; Emergency Closed Cooling B; Rev. 3
FPI-0CC Fire Zone 0CC-1B; Emergency Closed Cooling A; Rev. 3
FPI-1DG Fire Zone 1DG-1B; Unit 1 - Division 3 Diesel Generator Building; Rev. 3
FPI-0EW; Emergency Service Water Pumphouse; Rev. 4
FPI-0IB Fire Zone 0IB-4; Intermediate Building; Rev. 4
FPI-0IB Fire Zone 0IB-5; Intermediate Building; Rev. 4
FPI-0CC Fire Zone 1CC-5A; Unit 1 Control Room; Rev. 5
FPI-0CC Fire Zone 1CC-5B; Unit 2 Control Room; Rev. 5
FPI-0CC Fire Zone 1CC-3D; Unit 1 Remote Shutdown Panel Room; Rev. 5
FPI-0IB Fire Zone 0IB-2; Intermediate Building; Rev. 4
Fire Drill Planning Guide; Scenario #: FD-1525-063005; dated June 30, 2005

1R07 Heat Sink Performance

American Standard Drawing; #17oS4 CPK Exchanger; dated April 20, 1976
CHI-0004; System Chemical Treatment; Rev. 5
Calculation P45-081; Evaluation of Net Positive Suction Head (NPSH) and Submergence Requirements for the Emergency Service Water (ESW) System Pumps; dated September 28, 2004
Calculation E12-82; Calculation of the Minimum Required Wall Thickness for RHR Heat Exchangers 1E12-B0001A/B/C/D; Rev. 1
Calculation E12-89; Required ESW Flow for the RHR HXs; Rev. 3
Calculation E12-094; RHR A/C Heat Exchanger Performance Test Results; Rev. 0; dated November 12 1998
Calculation E12-094; RHR A Heat Exchangers Test Results; Rev. 1
Calculation E12-105; Residual Heat Removal System Heat Exchanger “A” Loop Performance Test Evaluation; Rev. 0; dated November 12 1998
Calculation E12-106; Residual Heat Removal System Heat Exchanger “A” Loop Performance Test Evaluation; Rev. 0; dated December 20, 2000
Calculation E22-037; Design Basis Heat Load and Required ESW Flow for the HPCS DGJW HX; Rev. 2
Calculation E22-041; Div 3 Emergency Diesel Generator Jacket Water Heat Exchanger Performance Test Evaluation; Rev. 0; dated August 27, 2003

Calculation E22-042; Div 3 Emergency Diesel Generator Jacket Water Heat Exchanger Performance Test Evaluation; Rev. 0; dated August 25, 2004
CR 01-3711; Silt Removal Criteria for ESWPH; dated October 22, 2001
CR 04-05995; Silt and Zebra Mussel Shell Deposition in ESW Intake Piping; dated November 16, 2004
CR 04-06180; Calculation for Silt Removal Criteria Doesn't Consider Tunnel Length/Silt/Bio-Fouling; dated November 23, 2004
CR 04-06253; PY-C-04-04 EMARP-011 Lacks Silt Inspection Requirements at Lake Water Intake Heads; dated November 29, 2004
CR 04-06273; Calculation for Silt Removal Does Not Consider Tunnel Length and Sediment; November 30, 2004
CR 04-06414; Overall Cause and Impact of Silt and Mussel Deposition in Intake Tunnel; dated December 12, 2004
Drawing 4549-21-016 Sheet 001; Residual Heat Removal Heat Exchanger 1E12B001A Tube Sheet Drawing; Rev. 1
Drawing 4549-21-016 Sheet 003; Residual Heat Removal Heat Exchanger 1E12B001C Tube Sheet Drawing; Rev. 1
Drawing 22-0139-00000; Division III Diesel Generator Jacket Water Heat Exchanger 1E22B5002 Tube Sheet Drawing; Rev. 1
EDG-97-009; Heat Exchanger Performance Testing Data Evaluation; Rev. 1
G/C Report No. 3023; Test Protocol Cleveland Electric Illuminating Company PNPP RHR Heat Exchangers; Rev. 1
GE Drawing 762E108; Residual Heat Removal System; Rev. C
GE 22A4206AA; RHR Heat Exchanger Revision Status Sheet; Rev. 2
HU-476-053; Engine Water Cooler Specification Sheet; Rev. 1
IOI-15; Seasonal Variations; Rev. 5
ISI-GEN-T3000; Pipe Wall Thickness Monitoring Examination Area Sheet EC-18; Rev. 1
ISI-GEN-T3000; Pipe Wall Thickness Monitoring Examination Area Sheet EC-22; Rev. 1
ISI-GEN-T3000; Pipe Wall Thickness Monitoring Examination Area Sheet EC-26; Rev. 1
ISI-GEN-T3000; Pipe Wall Thickness Monitoring Examination Area Sheet EC-68; Rev. 1
ISI-GEN-T3000; Pipe Wall Thickness Monitoring Examination Area Sheet EC-71; Rev. 1
Letter PY-CEI/NRR-1121; PNPP Response to Generic Letter 89-13, Service Water System Affecting Safety-Related Equipment; dated January 26, 1990
Letter PY-CEI/NRR-1734L; Implementation of Generic Letter 89-13, Service Water System Problems Affecting Safety-Related Equipment; dated April 8, 1994
NEI-0362; Engineering Design Guides; Rev. 3
ONI-P40; Frazil Ice; Rev. 2
ONI-R36-2; Extreme Cold Weather; Rev. 1
PAP-1117; Inspection Report of Visual Inspection Div 3 DG HX (ESW Side); dated April 23, 1996
PIFRA NO. 95-1926-004; Develop Programmatic Guidance for Appropriate Capture, Use and Control of Design Criteria Versus Guidance; dated May 21, 1997
PIFRA NO. 95-1926-005; Review and Revise Design Guides and Other Affected Documentation to Be in Compliance with Programmatic Guidance Resulting from PIFRA 95-1926-004; dated December 10, 1997
PTI-GEN-P0024; Mussel Treatment; Rev. 7
PTI-E12-P0002; RHR Heat Exchangers A and C Performance Testing; Rev. 6
PTI-E22-P0007; HPCS Diesel Generator Jacket Water Heat Exchanger Performance Testing; Rev. 2
SOI-E12; Residual Heat Removal System; Rev. 22

SOI-P48/P84B; Service Water and Emergency Service Water Chlorination and Dechlorination Systems; Rev. 10
Specification 22A4206AA; RHR Heat Exchanger Specification Sheet; Rev. 1
TAI-0515; Heat Exchanger Performance Monitoring; Rev. 1
WO 150890; Diver Insp ESW Forebay and Normal Intake
WO 200066712; ESW Pump A and Valve Operability Test; dated March 23, 2005
WO 200086677; Silt Smpl-diver Insp* ESW Forebay; dated January 26, 2005
WO 200094880; Ultrasonic Thickness Test for RHR Heat Exchanger C; dated March 17, 2005
WO 200119094; ESW System Loop C Flow and Differential Pressure Test; dated March 17, 2005

1R11 Licensed Operator Requalification

Simulator Guide OTLC-3058200502 PY-SGC2; Scenario Exam 2; Rev. 0
CR 05-04292; Shift Manager Peer Verifier Unsat Observation for Night Shift Starting 5/13/2005; dated May 15, 2005
CR 05-04289; Shift Manager Peer Verifier Observation for 05-15-05 (Days) Overall Unsat; dated May 15, 2005

1R12 Maintenance Effectiveness

CR 03-06739; 1P42-F665A Disconnect EF1A09-S Blown Fuses; December 21, 2004
CR 04-04158; Cycle Timer for the “A” Control Complex Chiller (P47) Suspected to Have Failed; dated August 12, 2004
CR 04-04181; Received Replacement Timer That Does Not Work Properly; dated August 13, 2004
CR 04-04485; Unanticipated Breaker Response During Test; dated August 30, 2004
CR 04-04649; Control Complex “C” Chiller Trip on High Refrig Discharge Temp; dated September 4, 2004
CR 04-04816; Timer Manufacturer Makes Changes That Has Potential to Affect Qualification; dated September 17, 2004
CR 05-02339; Cycle Timer Failed For the “C” Control Complex Chiller; dated March 16, 2005
CR 05-02457; Control Complex Chiller C Trip; dated March 19, 2005
CR 05-03066; NRC ID: Issue With Oil Feed Supply Lines for P42 and P47 Pumps; dated April 4, 2005
CR 05-03361; Chiller Light Indication Was Lost and Chiller Failed to Trip From Load Recycle; dated April 13, 2005
CR 05-03424; Problem With P47 Chiller Lamp in Control Room H13P870; dated April 15, 2005
PYRM-PII-0002; Perry Nuclear Power Plant Performance Improvement Initiative Fuel Reliability Improvement Strategic Plan; Rev. 2
Fuel Solution Team Interim Report; dated November 19, 2004
Maintenance Rule J11 Fuel System Monitor Record; dated May 13, 2005
CR 05-04148; Potential Repeat Maintenance N27 RFPT’S; dated May 8, 2005
CR 05-04050; Motor Feed Pump Flow Control Valve Went Full Open; dated May 4, 2005
CR 05-04143; Loss of Speed Control On RFPT A; dated May 8, 2005
CR 05-04138; Potential For Repeat Maintenance - Flow Transmitter; dated May 8, 2005

CR 05-04239; SOI-N27 Needs Steps to Bypass Feedpump Suction Flow Transmitters; dated May 11, 2005
CR 05-04208; As Found Condition Of 1N27F0670A; dated May 11, 2005

1R13 Maintenance Risk Assessments and Emergent Work Control

Shutdown Safety Status; dated April 1, 2005, through May 3, 2005
CR 05-04351; Failure of APRM D/H P23 Power Supply; dated May 18, 2005
NOP-OP-1005; Shutdown Safety; Rev. 8
CR 05-03026; Unexpected Results During F1F14 Outage Preps; dated April 4, 2005
CR 05-04335; F1F14 Outage Preps Impacted In-Service DHR System; dated May 17, 2005
PNPP Form No. 10242; Division 3 Outage (Yellow) Protected Equipment Posting Checklist; dated September 13, 2004
Perry Work Implementation Schedule; Week 4, Period 1
Probabilistic Safety Assessment; Week 4, Period 1; Rev. 0
Operations Evolution Order; De-energize/Re-energize F1F14; dated April 2, 2005

1R14 Operator Performance During Non-routine Evolutions and Events

TXI-0359; Digital Feedwater Control System Startup Test and Tuning; Rev. 0
IPTE Checklist Number 2005-010; Digital Feedwater Control System Tuning and Testing; Rev. 2
SOI-C34; Feedwater Control System; Rev. 16
PAP-1121; Conduct of Infrequently Performed Tests or Evolutions; Rev. 2
CR 05-04168; Valve Found Out of Position; dated May 10, 2005
CR 05-03943; Erratic Indications on Level Instrumentation; dated May 1, 2005
CR 05-03941; Unsat Observation for Shift Manager Peer Verifier for May 1, 2005 (Days); dated May 1, 2005
IOI-3; Power Changes; Revs. 20 and 21
CR 05-04286; Main Turbine Bypass Valve Opened While Increasing Power; dated May 14, 2005
ONI-ZZZ-6; Leak in Underground Piping; Rev. 2

1R15 Operability Evaluations

CR 05-03666; M23/24 May Not Fully Comply with IE Bulletin 80-06; dated April 21, 2004
NRC Bulletin 80-06; Engineered Safety Feature Reset Controls; dated March 13, 1980
CR 05-02762; Abandoned Unit 2 ESWPH Ventilation Inlet Dampers; dated March 28, 2005
Calculation GEN-018; Bolt Thread Engagement; Rev. 0
CR 05-03800; 1E12C0003 Discharge Flange Inadequate Thread Engagement; dated April 26, 2005
CR 05-04204; Division 1 D/G Output Breaker EH1102; dated May 10, 2005

1R16 Operator Workarounds

M&C.-14; Work Around Policy; dated February 15, 2000
Operator Work Around Log; dated April 14, 2005
Operator Work Around Log; dated May 31, 2005

1R17 Permanent Plant Modifications

ECP 05-0044; RCIC Head Spray Pressure Indication; Rev. 0

1R19 Post-Maintenance Testing

CR 05-03410; Div 2 DG Hunting; dated April 13, 2005
SVI-E22-T2002; HPCS Waterleg Pump and Associated Valves Cold Shutdown Operability Test; Rev. 12
NQI-1001; QC Inspection Program Control; Rev. 4
Problem Solving Plan; Feedwater Flow Excursion; Rev. 4
CR 05-04038; Feedwater Flow Excursion; dated May 4, 2005
WO 200155454; Troubleshoot/rework abnormal annunciator flash rates; dated June 13, 2005
CR 05-04967; Control Room 1H13P680 Annunciator Abnormalities; dated June 22, 2005
WO 200065570; CRD Pump B Breaker; dated June 23, 2005
CR 03-05820; XH1201 Breaker Springs Did Not Discharge as Expected; dated October 20, 2003
WO 200147584; EQ ID OP54C0002 P54, Motor Fire Pump; dated June 28, 2005
CR 05-05040; Unplanned Fire Impairment - Motor Fire Pump; dated June 27, 2005

1R20 Refueling and Outage Activities

NOBP-OM-4010; Restart Readiness for Plant Outages; Rev. 2
CR 05-01342; Bent Threaded Rod on Steam Line Support; dated February 23, 2005
CR 05-02671; Staking of Setscrews Attaching Lineshaft Sleeves to Lineshafts; dated March 25, 2005
CR 05-02840; Upper Airlock Outer Door; dated March 30, 2005
CR 05-01591; Possible Extensive Optical Isolator Failures for Neutron Monitoring; dated February 28, 2005
CR 05-02242; Jet Pump Assembly Restrainer Bracket Wedge Wear; dated March 14, 2005
CR 05-02659; Fuel Bundle Contact with Vessel During Vessel to Vessel Move; dated March 25, 2005
CR 05-02323; Dampers M25F130A And M25F130B May Not Meet Technical Specification SR 3.7.3.3; dated March 16, 2005
CR 05-03061; Suspect Unapproved Use of O-Ring Lubricant on the SRV Solenoid Elect Connections; dated April 6, 2005
IOI-1; Cold Startup; Rev. 15
CR 05-04038; Feedwater Flow Excursion; dated May 4, 2005
CR 05-03947; Unexpected Events During Reactor Mode Switch Operation; dated May 2, 2005

1R22 Surveillance Testing

CR 05-03054; Unexpected Valve Strokes During Performance of SVI-R43-T1338; dated April 5, 2005
CR 05-03026; Unexpected Results During F1F14 Outage Preps; dated April 4, 2005
SVI-R43-T1338; Division 2 Standby Diesel Generator Loss of Offsite Power (LOOP) Test; Rev.s 7, 9, 11, and 13
CR 05-03366; Assess Effect of Running Division 2 LOOP LOCA with Degraded Div. 2 DG Governor; dated April 13, 2005

CR 05-03353; Expectations Not Met During Div 2 LOOP Test; dated April 14, 2005
CR 05-03369; PCR for Deficiency in PMI-0011 for Div 2 Diesel Tuning; dated April 13, 2005
CR 05-03344; Division 1&2 LOOP DG Response; dated April 13, 2005
SVI-E22-T1329; Division 3 HPCS Diesel Generator Functional Test; Rev. 8
CR-05-03627; Breaker EH1302 Failed to Close for SVI-E22-T1339; dated April 21, 2005
Control Room Log Entries Report; dated April 21, 2005
SVI-E22-T1339; Division 3 HPCS Diesel Generator Loss of Off-Site Power Test; Rev. 3
ISI-B21-T1300-1; Reactor Coolant System Leakage Pressure Test; Rev. 12
SVI-E12-T2001; RHR A Pump and Valve Operability Test; Rev. 19
WO 200113347; RHR A Pump and Valve Operability Test; dated May 19, 2005
WO 200136253; Off-Gas Post-Treatment Radiation Monitor Channel A Functional for 1D17-K601A; dated June 13, 2005
CR 05-04072; Low Flow on Off-Gas Post-Treatment Radiation Monitor; dated May 5, 2005
CR 05-04059; Offgas Post-Treat Valve Out of Position; dated May 5, 2005
SVI-D17-T8015-A; Off-Gas Post-Treatment Radiation Monitor Channel A Functional for 1D17-K601A; Rev. 3
NOP-WM-2003; Work Management Surveillance Process; Rev. 0
Human Performance Job Brief Card for WO 200136253; dated June 13, 2005
SVI-C41-T2001-B; Standby Liquid Control B Pump and Valve Operability Test; Rev. 9
WO 200113248; Standby Liquid Control B Pump and Valve Operability Test; dated June 21, 2005
SOI-C41; Standby Liquid Control System; Revs. 11 and 12
CR 05-02246; PCR - Deficiency - Standby Liquid Control (C41); dated March 15, 2005
CR 05-02927; NRC ID: Pipe to Standby Liquid Control Pump "B" Oil Sightglass is Bent; dated March 30, 2005

1EP6 Drill Evaluation

Controller's Book; Perry Power Plant 2005 ERO Team "C" Drill; dated May 9, 2005

4OA2 Identification and Resolution of Problems

Project Plan for Maintenance Procedures Upgrade Associated with Key Critical Components; Rev. 1
CR 05-04064; Nuclear Oversight [PYOV] Human Performance Clock Reset Indicator is Red; dated May 5, 2005
Perry Nuclear Power Plant Performance Improvement Initiative Detailed Action and Monitoring Plan; Rev. 3
GMI-0021; General Torquing; Rev. 2 and Rev. 8
CR 05-03800; 1E12C0003 Discharge Flange Inadequate Thread Engagement; dated April 26, 2005
CR 04-01465; Ineffective CR/ CR Investigation Related to Inadequate Thread Engagement; dated March 23, 2004
CR 01-1518; Inadequate Thread Engagement Condition on RHR/ E12 Pipe Flange; dated March 19, 2001
CR 00-2471; Inadequate Thread Engagement Concerns on Bolted-Flanged Connections; dated August 15, 2000
CR 00-2487; Inadequate Thread Engagement on HPCS Line Fill Pump Discharge Flange; dated August 17, 2000

WO 00-007806-000; RHR Watereg Pump Discharge Flange Thread Engagement; dated August 22, 2000
CR 05-02616; Questions Raised by NRC Inspector After Div 1 Walk Down; dated March 23, 2005
CR 05-03269; Inadequate Thread Engagement; dated April 12, 2005
CR 05-03270; Inadequate Thread Engagement; dated April 12, 2005
CR 05-03675; Inadequate Thread Engagement on Two Anchor Bolts - Div 1 D/G Platform Supports; dated April 22, 2005
CR 05-04411; P42-F140 Stem Packing Nut Thread Engagement; dated May 22, 2005
CR 05-03640; SVI-G33-T2002B Failed Its Exercise Close Tech Spec Portion of the Test; dated April 21, 2005
CR 05-04112; Temporary Test Gauges Left Installed After Troubleshooting of G33F052B; dated April 30, 2005
WO Addendum 200147914-A1; 1G33F0052B Failed Exercise Close (EC) Post Maintenance Test; dated April 29, 2005
WO Addendum 200147914-A2; Restoration of RWCU Leak Detection Flow Detector to Service; dated May 6, 2005
SVI-G33-T2002B; RWCU Check Valve 1G33-F052B Operability Test; Rev. 3
NOBP-OM-4010; Restart Readiness for Plant Outages; Rev. 2
IOI-1; Cold Startup; Rev. 17
SOI-E31; Leak Detection System; Rev. 6
WO 200147914; Temporary Condition Log/Restoration Verification; dated May 6, 2005
DWG SS-803-070; Leak Detection System Return to Feedwater 1E31-N077B; Rev. D

4OA3 Event Followup

Root Cause Report; LCO 3.0.3 Entry Due to Inoperable Testable Relief Devices on Diesel Generators; dated April 1, 2005
ECP 04-0169; The Testable Rupture Disk Will Be Replaced Along with Associated Lugs; Rev. 0
ECP 04-0170; The Testable Rupture Disk Will Be Replaced Along with Associated Lugs; Rev. 0

4OA5 Other Activities

ONI-S11; Unstable Grid; Rev. 1
PAP-0102; Interface With the Transmission System Operator; Rev. 2
ONI-SPI F-1; Off-Site Power Restoration; Rev. 1
PAP-1604; Reports Management; Rev. 13
PAP-1924; Risk-Informed Safety Assessment and Risk Management; Rev. 4
ONI-R10; Loss Of A.C. Power; Rev. 8

LIST OF ACRONYMS USED

CFR	*Code of Federal Regulations*
CR	condition report
ECC	emergency closed cooling
EDG	emergency diesel generator
EPRI	Electrical Power Research Institute
ESW	emergency service water
FENOC	FirstEnergy Nuclear Operating Company
FIN	Finding
FPCC	fuel pool cooling and clean-up
FPFD	fuel pool filter demineralizer
GMI	general maintenance instruction
HPCS	high pressure core spray
HVAC	Heating ventilation and air conditioning
IMC	Inspection Manual Chapter
LDS	leak detection system
LER	Licensee Event Report
LOOP	loss of offsite power
LPCS	low pressure core spray
MFP	motor feed pump
NCC	nuclear closed cooling
NCV	non-cited violation
NOP	Nuclear Operating Procedure
NRC	Nuclear Regulatory Commission
OA	Other Activities
OE	operability evaluation
ONI	Off-Normal Instruction
OWA	operator work around
PAP	Perry Administrative Procedure
PDB	Plant Data Book
PMT	post-maintenance testing
RCIC	reactor core isolation cooling
RFO10	Refueling Outage 10
RHR	residual heat removal
RO	Reactor Operator
RWCU	reactor water cleanup
SDP	significance determination process
SRA	Senior Risk Analyst
SRO	Senior Reactor Operator
SSC	structures, systems, and components
SVI	surveillance instruction
TI	Temporary Instruction
TRD	testable rupture disks
TS	Technical Specification
USAR	Updated Safety Analysis Report
VLI	valve lineup instruction
WO	work order