July 8, 2005

EA 03-197
EA 04-020
EA 04-214
EA 05-141

Mr. R. Anderson
Vice President
FirstEnergy Nuclear Operating Company
Perry Nuclear Power Plant
P. O. Box 97, A290
10 Center Road
Perry, OH 44081

SUBJECT: PERRY NUCLEAR POWER PLANT
INSPECTION PROCEDURE 95003 SUPPLEMENTAL INSPECTION
NRC INSPECTION REPORT 05000440/2005003

Dear Mr. Anderson:

The purpose of this letter is to provide you with Inspection Report (IR) 05000440/2005003, detailing the results of our recent "Supplemental Inspection for Repetitive Degraded Cornerstones, Multiple Degraded Cornerstones, Multiple Yellow Inputs, or One Red Input," conducted in accordance with Inspection Procedure (IP) 95003. You and other members of your staff attended the May 26, 2005, public exit meeting held at the Quail Hollow Resort in Painesville, Ohio during which the results of this three-part supplemental inspection were presented. A summary of the public meeting was documented in a letter to you dated June 3, 2005.

The NRC's Reactor Oversight Process (ROP) collects information to enable the agency to arrive at objective conclusions about a licensee's safety performance. The assessment information is used to determine the appropriate agency response. The NRC's Action Matrix, found in Inspection Manual Chapter (IMC) 0305, "Operating Reactor Assessment Program," delineates expected NRC and licensee actions based on the inputs to the assessment process. Agency action beyond the baseline inspection program will normally occur only if assessment input thresholds are exceeded. The Action Matrix identifies the range of NRC and licensee actions and the appropriate level of communication for varying levels of licensee performance. The Action Matrix describes a graded approach in addressing performance issues. From 2002 to 2004, plant performance at Perry had steadily declined. An outline of plant performance since 2002 and a discussion of the NRC's response is included in the Performance Background section of the enclosed report.

The IP 95003 inspection is designed to allow the NRC to obtain a comprehensive understanding of the depth and breadth of safety, organizational, and performance issues at facilities where data indicates the potential for serious performance degradation. The inspection was an examination of activities conducted under your license as they relate to safety and to compliance with the Commission's rules and regulations and with the conditions of your license. Within these areas, the inspection consisted of a selective review of procedures and representative records, observations of activities, and interviews with personnel.

The scope of the IP 95003 inspection included the assessment of performance in the Reactor Safety strategic performance area, including attributes such as design, human performance, procedure quality, equipment performance, configuration control, and emergency response. The inspection also reviewed your control system for identifying, assessing, and correcting performance deficiencies to evaluate whether it was sufficient to prevent a further decline in performance that could result in unsafe operation.

During the inspection, the team reviewed your actions to address the deficiencies identified during the May 2004, IP 95002 inspection. These deficiencies confirmed the need for a thorough assessment of the common causes of inadequate procedures, inadequate procedure adherence, and ineffective training, as well as corrective actions to address repetitive ESW pump failures. The NRC also conducted a detailed review of the Perry Performance Improvement Initiative (PII). The PII was a program implemented by FirstEnergy to improve performance, using insights from Inspection Procedure 95003, lessons learned from the Davis-Besse Nuclear Power Station, and lessons learned from other stations that were placed under the IP 95003 inspection process.

The IP 95003 inspection results concluded that your facility is being operated safely. However, the team identified problems similar to those previously identified at your Perry facility, particularly in the areas of human performance and problem identification and resolution. Overall, while some limited improvements may have been realized, the NRC concluded that there has been no substantial improvement in human performance or your implementation of the corrective action program since Perry entered the Multiple/Repetitive Degraded Cornerstone column of the NRC's Action Matrix in August 2004. This indicates the need for you to consider revising and/or accelerating the Perry PII. The areas of human performance and problem identification and resolution warrant your prompt attention, particularly as they relate to procedure adherence and the identification and implementation of corrective actions for known problems.

With regard to our review of your actions to address the deficiencies identified during the previous IP 95002 inspection, the NRC determined that your actions to address procedure adequacy, training, and emergency service water pump failures were still in progress at the end of our IP 95003 inspection. Although no additional pump failures have occurred since pump repair activities were accomplished in May 2004, the team identified that one of your corrective actions to address the verification of the quality of emergency service water pump work was inadequate. In light of the continuing problems in human performance and the impact on procedure adherence, the team concluded that actions to address procedure adherence have not been fully effective. In addition, we determined that your actions to address training concerns were not timely and were still in progress at the end of our inspection. As a result of our IP 95003 inspection findings, the NRC concluded that the White findings that were left open at the conclusion of the IP 95002 inspection will remain open pending your additional actions, the NRC's review of those actions, and a determination that actual performance improvements have been made in the human performance and problem identification and resolution areas.

The NRC determined that your PII established a formal systematic process for reviewing programs and procedures, and determining common causes; and if issues exist, whether their significance merits further review. However, during our review of your implementation of this plan, we identified instances where actions that were considered to be complete had not been adequately implemented. Although none of these examples was significant, it indicated a shortcoming in the implementation of the PII that warrants your attention.

You are requested to respond within 30 days of the date of this letter. Your response should describe the specific actions that you plan to take to address the issues raised during this inspection and improve plant performance.

The NRC will continue to provide increased oversight of activities at your Perry Nuclear Power Plant, including your steps taken to improve your PII and its implementation, until you have demonstrated that your corrective actions are lasting and effective. Consistent with IMC 0305 guidance regarding the oversight of plants in the Multiple/Repetitive Degraded Cornerstone column of the NRC's Action Matrix, the NRC will continue to assess performance at Perry and will consider at each quarterly performance assessment review the following options: (1) declaring plant performance to be unacceptable in accordance with the guidance in IMC 0305; (2) transferring the facility 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. Until you have demonstrated lasting and effective corrective actions, Perry will remain in the Multiple/Repetitive Degraded Cornerstone column of the NRC's Action Matrix.

Based on the results of this inspection, 25 findings of very low safety significance (Green), 23 of which had an associated Non-Cited Violation (NCV), were identified. However, because of the very low safety significance and because the violations were entered into your corrective action program, the NRC is treating the issues as Non-Cited Violations in accordance with Section VI.A.1 of the NRC Enforcement Policy. These NCVs are described in the subject inspection report. If you contest the subject or severity level of a Non-Cited Violation, 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 NRC Resident Inspector at the Perry facility.

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 by Geoffrey E. Grant for/

James L. Caldwell
Regional Administrator

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

Enclosures: Inspection Report 05000440/2005003
w/Attachments: 1. IP 95003 Inspection Findings
2. Perry Performance Improvement Initiative Review
3. Supplemental Information

See Attached Distribution

See Previous Concurrences

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-440
License No:	NPF-58
Report No:	05000440/2005003
Licensee:	FirstEnergy Nuclear Operating Company (FENOC)
Facility:	Perry Nuclear Power Plant
Location:	10 Center Road Perry, Ohio 44081
Dates:	Corrective Action Program, January 10 through 28, 2005 Outage Activity Review, February 22 through 25 and March 14 through 25, 2005 Engineering, Operations, and Maintenance, April 4 through May 6, 2005
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Approved by: C. Lipa, Chief
Branch 4
Division of Reactor Projects

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Executive Summary

As a result of poor performance, the Nuclear Regulatory Commission (NRC) designated the Perry Nuclear Power Plant (PNPP), owned and operated by FirstEnergy Nuclear Operating Company, as a "Multiple/Repetitive Degraded Cornerstone Column" facility in the NRC's Action Matrix[1] in August 2004. Accordingly, a supplemental inspection was performed in accordance with the guidance in NRC Inspection Manual Chapter (IMC) 0305 and Inspection Procedure (IP) 95003, "Supplemental Inspection for Repetitive Degraded Cornerstones, Multiple Degraded Cornerstones, Multiple Yellow Inputs, or One Red Input." A multi-disciplinary team conducted the inspection in three parts over the course of about 5 months, with a total of 8 weeks of onsite effort. This report contains the results of that inspection. The objectives of the inspection included the following:

- To provide the NRC additional information to be used in deciding whether the continued operation of the Perry facility was acceptable and whether additional regulatory actions were necessary to arrest declining performance;

- To provide an independent assessment of the extent of risk-significant issues to aid in the determination of whether an acceptable margin of safety exists;

- To independently evaluate the adequacy of the programs and processes used to identify, evaluate, and correct performance issues;

- To independently evaluate the adequacy of programs and processes in the Reactor Safety strategic performance area; and

- To provide insight into the overall root and contributing causes of identified performance deficiencies.

In addition, the scope of this inspection included the review of licensee actions to address the deficiencies identified during a previous IP 95002 inspection. In particular, the team reviewed the licensee's root cause and corrective actions to address the areas of procedure adequacy, procedure adherence, and training deficiencies identified in the previous IP 95002 inspection; as well as the problem identification, root cause review, and corrective actions to address repetitive emergency service water (ESW) pump coupling failures. An independent extent of condition and extent of cause review was also conducted to independently assess the validity of the licensee's conclusions regarding the extent of condition and extent of cause of the issues.

By letter dated September 30, 2004, FirstEnergy advised the NRC that actions were underway to improve plant performance. To facilitate these performance improvements, FirstEnergy developed the Perry Performance Improvement Initiative (PII). As part of this IP 95003 inspection, the team conducted a detailed review of the PII. This review consisted of two parts. The first part of the inspection consisted of a review of the scope of the PII and determined whether the PII, if implemented as written, could be expected to achieve the overall goal of

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[1]The NRC's Action Matrix is described in Inspection Manual Chapter 0305, "Operating Reactor Assessment Program."

correcting the declining trend of performance at Perry. The second part of the review consisted of an inspection of the licensee's implementation of selected actions prescribed in the PII Detailed Action & Monitoring Plan.

In the assessment of the Reactor Safety strategic performance area, the team selected the residual heat removal (RHR) system and the Division 1 and Division 2 emergency diesel generators (EDGs) for in-depth reviews. The selection was based on two criteria, the first being the systems' importance to overall plant risk, and the second related to performance issues associated with these systems. The team selected the RHR system because performance issues associated with this system had not been identified recently, and in contrast the EDGs were selected because many self-revealed performance issues had been recently identified. These selections provided the team the opportunity to review both the licensee's ability to identify issues as well as the licensee's ability to identify and implement corrective actions to address identified issues. With respect to these systems, the inspection focused heavily on the design aspects, the quality of procedures, configuration control, and equipment performance. Additionally, the team reviewed the licensee's programs and processes associated with human performance and emergency preparedness.

Overall, the team determined that an adequate margin of safety was found to exist and therefore Perry was being operated safely. The team determined that the programs and processes to identify, evaluate, and correct problems, as well as other programs and processes in the Reactor Safety strategic performance area were adequate.

Notwithstanding these overall conclusions, the team determined that the performance deficiencies that occurred prior to and during the inspection were often the result of inadequate implementation of the corrective action program (CAP) and human performance errors. Specifically, although the overall implementation of the CAP was adequate, numerous findings and observations in the CAP area were identified, particularly in the identification and implementation of corrective actions. These findings were identified in all focus areas, and were in all cases determined to be of very low safety significance.

The team identified that a number of factors contributed to CAP problems. A lack of rigor in the evaluation of problems was a major contributor to the ineffective corrective actions. For example, in the engineering area, when problems were identified, a lack of technical rigor in the evaluation of those problems at times resulted in an incorrect conclusion, which in turn affected the ability to establish appropriate corrective actions. The team also determined that corrective actions often were narrowly focused. In many cases a single barrier was established to prevent a problem from recurring. However, other barriers were also available which, if identified and implemented, would have provided a defense-in-depth against the recurrence of problems. The team also identified that problems were not always appropriately prioritized, which led to the untimely implementation of corrective actions. A number of programmatic issues were identified that have resulted in the observed CAP weaknesses. For example, the team identified a relatively high threshold for classifying deficiencies for root cause analysis. As a result, few issues were reviewed in detail. In addition, for the problems that were identified that required a root cause evaluation, the team found that the qualification requirements for root cause evaluators were limited and multi-disciplinary assessment teams were not required. The team also identified that a lack of independence of evaluators existed. This resulted in the same individuals repeatedly reviewing the same issues without independent and separate review. In addition, the team identified weaknesses in the trending of problems, which has hindered the ability to correct problems at an early stage before they become more significant issues. Finally, the team determined that a lack of adequate effectiveness reviews was a barrier to the identification of problems with corrective actions that had been implemented. Overall, the NRC concluded that while some limited improvements may have been realized, there has been no substantial improvement in the licensee's implementation of the corrective action program since Perry entered the Multiple/Repetitive Degraded Cornerstone column of the NRC's Action Matrix.

In the area of design, the team concluded that the systems, as designed, built, and modified, were operable and that the design and licensing basis of the systems were sufficiently understood. Notwithstanding the overall acceptability of performance in the engineering area, the team identified common characteristics in a number of problems identified during the inspection. These characteristics included a lack of technical rigor in engineering products that resulted in an incorrect conclusion. Some findings and observations related to design modifications and engineering-related corrective actions to address performance deficiencies were identified. Also, there appeared to be a lack of questioning by the licensee staff of some off-normal conditions. Finally, weaknesses in the communications between engineering and other organizations such as operations and maintenance sometimes hindered the resolution of problems.

In the area of human performance, the team determined that a number of self-revealed findings relating to procedure adherence occurred that had a strong human performance contribution. These findings emanated from events that have resulted in an unplanned engineered safety feature actuation, a loss of shutdown cooling, an unplanned partial drain down of the suppression pool, inadvertent operation of a control rod (a reactivity event), and other configuration control errors. The team reviewed the events that occurred during the inspection and identified that the procedure adherence problems had a number of common characteristics. In a number of cases, personnel failed to properly focus on the task at hand. Although pre-job briefings were held prior to many events, and procedures were adequate to accomplish the intended activity, personnel failed to sufficiently focus on the individual procedure step being accomplished and performed an action outside of that prescribed by the procedure. In some cases, the team determined that a lack of a questioning attitude contributed to the procedure problems that occurred. Although information was available to personnel that, if fully considered, could have prevented the procedure adherence issues that occurred, that information was not sought out or was not questioned. The presence of supervisors with the necessary standards to foster good procedure adherence could have acted as a significant barrier to prevent some of the problems that occurred. However, adequate supervisory oversight was not always available or used. Further, the team identified that available tools for assessing human and organizational performance had not been effectively used. Overall, the NRC concluded that while some limited improvements may have been realized, there has been no substantial improvement in human performance since Perry entered the Multiple/Repetitive Degraded Cornerstone column of the NRC's Action Matrix.

In the area of procedure adequacy, the team determined that the licensee's procedures to safely control the design, maintenance, and operation of the plant were adequate, but warranted continued management focus and resource support. In particular, process-related vulnerabilities in areas such as periodic plant procedure reviews, procedure revisions, and use classifications were identified by the team.

In the area of equipment performance, the team acknowledged that the licensee had completed numerous recent plant modifications to improve equipment performance. In addition, improved engineering support and management oversight of equipment performance were noted. Notwithstanding the above, the team identified numerous examples that indicated that the resolution of degraded equipment problems and implementation of the CAP continued to be a challenge to the organization.

In the area of configuration control, the team identified numerous examples that indicated the resolution of configuration control issues and implementation of the CAP continued to be a challenge to the organization. The team agreed with the licensee's assessment that continuing configuration control problems were primarily the result of inappropriate implementation of procedural requirements rather than the result of configuration management procedural shortcomings. However, given the on-going errors associated with equipment alignment, as well as multiple errors associated with maintenance configuration control such as scaffolding erection, the team concluded that adequate evaluations of the root causes of configuration control errors had not been performed. The team also concluded that the licensee lacked rigor in its efforts to resolve latent configuration control issues. Several licensee-identified issues have not been corrected, and contributed to configuration control shortcomings.

In the area of emergency preparedness, the team determined that there were some performance deficiencies associated with the licensee's implementation of the Emergency Plan. A number of findings were identified in which changes to the Emergency Plan or Emergency Action Levels were made without required prior NRC approval. In addition, the results of the augmentation drill where personnel were called to report to the facility for a simulated emergency were unsatisfactory. The Technical Support Center was not able to be declared operational within timeliness goals. However, these findings were characterized as being of only very low safety significance.

The team reviewed the licensee's actions to address weaknesses in the areas of procedure adequacy, procedure adherence, and training identified in the previous IP 95002 inspection. This included the problem identification, root cause review, and corrective actions to address repetitive ESW pump coupling failures. The team determined that actions to address procedure adequacy and ESW pump failures was still in progress at the end of this inspection. Although no additional pump failures have occurred since pump repair activities were accomplished, the team identified that one of the licensee's corrective actions to address the verification of the quality of ESW pump work was inadequate. In addition, in light of the continuing problems in human performance and the impact on procedure adherence, the team concluded that actions to address procedure adherence have not been fully effective. Finally, actions to address training were also still in progress at the end of the inspection. In this case, the licensee's corrective actions to address this issue have not been timely and to date, have not been implemented. As a result, the NRC concluded that the open White findings associated with the IP 95002 inspection will continue to remain open pending additional licensee actions and the NRC's review of those actions.

In the assessment of the licensee's performance improvements planned and implemented through the Perry PII, the team determined that the Perry PII has a broad scope and addresses many important performance areas. The team also observed that, although substantially completed, the PII has not resulted in significant improvement in plant performance in several areas. There are a number of apparent reasons why this has occurred, one being that the PII is largely a discovery activity, and as such, many elements of the PII do not directly support improving plant performance. Instead, the problems identified through the PII reviews are entered into the CAP and the proper resolution of these problems depend upon the proper implementation of the CAP. During this inspection, the NRC identified that in some cases the CAP has not been implemented adequately to address the concerns identified during PII reviews. The team also observed that although PII items may be closed, the corrective actions to address the identified problems may not have been fully identified or implemented. The team also identified that a number of extensions has slowed the implementation of the PII. The team identified that although many PII actions have been completed, some of the more significant assessments, such as in the area of human performance, were still in progress at the end of the inspection. Overall, based on the factors discussed above, the NRC was unable to draw any definitive conclusions regarding the overall effectiveness of the Perry PII. As a result, further reviews will be necessary to determine whether the PII is sufficient to address and resolve the specific issues identified.

SUMMARY OF FINDINGS

IR 05000440/2005003; 1/10/2005 - 5/06/2005; Perry Nuclear Power Plant; IP 95003, “Supplemental Inspection for Repetitive Degraded Cornerstones, Multiple Degraded Cornerstones, Multiple Yellow Inputs, or One Red Input.”

This report covers a 5-month period of supplemental inspection by NRC inspectors from all four NRC Regional offices and from Headquarters. Green findings totaling 25, 23 of which had associated Non-Cited Violations (NCVs), were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using 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>NRC-Identified and Self-Revealed Findings</u>

Cornerstone: Initiating Events

- Green. A finding of very low safety significance and an associated NCV of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action,” was NRC-identified when licensee personnel failed to correct in a timely manner a condition adverse to quality regarding operators’ failure to use required human performance error reduction tools during stressful situations. The finding was of more than minor significance because the finding could reasonably be viewed as a precursor to a significant event since the continued deviation from established procedures and training during stressful times had the potential to result in an initiating event or result in more significant consequence following an initiating event.

  Using IMC 0609, “Significance Determination Process,” the team determined that this finding did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

  As part of the licensee’s immediate corrective actions, human performance tools were implemented which addressed the importance of procedure adherence during events and other stressful situations.

  This finding affected the cross-cutting area of Problem Identification and Resolution because licensee personnel failed to take corrective actions to address a condition adverse to quality in a timely manner.
  (Attachment 1, Item 1.13; NCV 05000440/2005003-16)

- Green. A finding of very low safety significance and an associated NCV of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action,” was NRC-identified when licensee personnel failed to implement adequate corrective actions for root causes associated with a significant condition adverse to quality. Specifically, the licensee identified “management failures in identifying problems with reactivity control systems” as a root cause for unexpected control rod movement, however licensee corrective actions failed to address this issue.

The team determined that the finding was of more than minor significance since it could be reasonably viewed as a precursor to a more significant event. Specifically, the corrective action intended to address management’s oversight of the reactivity control systems did not address the licensee’s identified cause and did not cover all activities that involve significant rod movement such as short forced outages and control rod pattern changes.

Although not suited for SDP evaluation, the finding was determined to be of very low safety significance because no initiating event occurred.

As part of the licensee’s corrective actions, Condition Report 03-05995 was previously generated to address organizational issues through the use of the Plant Health Committee, clarification of the roles and responsibilities of managers and directors, and to develop the Perry PII. (Attachment 1, Item 1.7; NCV 05000440/2005003-10)

Cornerstone: Mitigating Systems

- Green. A finding of very low safety significance and an associated NCV of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action,” was NRC-identified when licensee personnel failed to correct a condition adverse to quality identified in IR 05000440/2004008 regarding an NCV for the failure to properly inspect the re-assembly of ESW pump couplings. During this inspection, the team identified that licensee corrective actions to address this issue were inadequate and again failed to prescribe an appropriate inspection of the ESW pump couplings during re-assembly.

  The finding was of more than minor significance since the finding could be reasonably viewed as a precursor to a significant event. Specifically, the licensee failed to perform required inspections for the installation of mechanical equipment and this failure contributed to a previous ESW pump failure that was determined to be a White finding. The team noted that for both ESW pump failures, the pumps had satisfied post-maintenance testing acceptance criteria. Further, the team noted that improvements in quality control could have detected the conditions that led to premature pump failure. Specifically, inspections could have detected the misalignment of the coupling that led to the first pump failure and improved quality control of parts could have prevented the second failure.

  Using IMC 0609, “Significance Determination Process,” the team determined that this finding 1) was not a design deficiency or qualification deficiency; 2) did not represent an actual loss of safety function of a system; 3) did not represent an actual loss of safety function of a single train for greater than its Technical Specification (TS) allowed outage time; 4) did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant; and 5) did not screen as potentially risk significant due to seismic, flooding, or a severe weather initiating event. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

As part of the licensee's immediate corrective actions, this issue was entered into the CAP.

This finding affected the cross-cutting area of Problem Identification and Resolution because the finding was associated with the licensee's failure to adequately address a significant condition adverse to quality. (Attachment 1, Item 1.14; NCV 05000440/2005003-17)

- Green. A finding of very low safety significance and an associated NCV of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," was NRC-identified when licensee personnel failed to prevent repetition of a condition adverse to quality. Specifically, the standby liquid control (SLC) system pump discharge pressure relief valves failed to satisfy American Society of Mechanical Engineers (ASME) acceptance criteria for 6 of 10 in-service tests (ISTs) conducted over the last 20 years. On two occasions, in 1989 and 2001, the as-found relief valve condition would have prevented the SLC system from being able to perform its intended design function to mitigate an Anticipated Transient Without Scram (ATWS) event, coincident with a main steam isolation valve (MSIV) closure.

  The finding was of more than minor significance since the finding was associated with the equipment performance attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

  Using IMC 0609, "Significance Determination Process," the team determined that because this finding represented an actual loss of a safety function of one train of the system, a Phase 2 SDP analysis was required. In the Phase 2 SDP assessment, the ATWS event worksheet was reviewed as specified by the Perry Plant Risk-Informed Inspection Notebook. The dominant core damage sequence was an ATWS event, followed by a loss of the SLC system. The Phase 2 SDP assessment determined that this finding was of very low safety significance (Green) because 1 of 2 SLC pumps remained available.

  As part of the licensee's immediate corrective actions, licensee personnel compared the as-left setpoints for the currently installed relief valves to a design setpoint value, and ensured that an adequate margin existed for the SLC relief valves to adequately perform their safety function.

  This finding affected the cross-cutting area of Problem Identification and Resolution since licensee personnel did not adequately evaluate prior SLC relief valve as-found test failures. (Attachment 1, Item 1.1; NCV 05000440/2005003-04)

- Green. A finding of very low safety significance was self-revealed when repetitive drywell supply fan failures occurred due to inadequate maintenance and inadequate corrective actions to address a previous failure due to an identical root cause. No violation of regulatory requirements occurred.

  The finding was of more than minor significance since the finding could reasonably be viewed as a precursor to a more significant event since identically designed fans existed in other risk-significant plant systems and a failure of those fans, under similar circumstances, could have also occurred.

  Using IMC 0609, “Significance Determination Process,” the team determined that this finding 1) was not a design deficiency or qualification deficiency; 2) did not represent an actual loss of safety function of a system; 3) did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time; 4) did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant; and 5) did not screen as potentially risk significant due to seismic, flooding, or a severe weather initiating event. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

  As part of the licensee’s immediate corrective actions, the affected fan was repaired and an extent of condition review was performed.

  This finding affected the cross-cutting area of Problem Identification and Resolution since the finding involved inadequate corrective actions to address a previous failure. (Attachment 1, Item 1.3; FIN 05000440/2005003-06)

- Green. A finding of very low safety significance and an associated NCV of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action,” was NRC-identified when the licensee’s corrective actions following air-binding of the low-pressure core spray (LPCS)/RHR 'A' waterleg pump failed to identify that high point vent valves were omitted from venting procedures which had the potential to render the reactor core isolation cooling (RCIC) system inoperable, as discussed in prior operating experience information.

  The team determined that the finding was of more than minor significance since the finding was associated with the equipment performance attribute of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

  Using IMC 0609, “Significance Determination Process,” the team determined that this finding 1) was not a design deficiency or qualification deficiency; 2) did not represent an actual loss of safety function of a system; 3) did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time; 4) did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant; and 5) did not screen as potentially risk significant due to seismic, flooding, or a severe weather initiating event. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

As part of the licensee's immediate corrective actions, the affected high point vent was added to the licensee's venting procedures and the affected piping was verified to be properly vented and filled with water.

This finding affected the cross-cutting area of Problem Identification and Resolution because licensee personnel failed to perform an adequate extent of condition review for high point vent valves omitted from venting procedures. (Attachment 1, Item 1.4; NCV 05000440/2005003-07)

- Green. A finding of very low safety significance and an associated NCV of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," was NRC-identified when licensee personnel continued to use "Never-Seez" in safety-related motor-operated valve (MOV) applications although industry operating experience identified that "Never-Seez" was not an adequate MOV stem lubricant. As a result, over a 10-year period, licensee personnel deferred MOV stem lubricant replacement while multiple MOVs failed as-found test acceptance criteria and exhibited accelerated stem nut wear.

  The team determined that the finding was of more than minor significance since the finding was associated with the equipment performance attribute of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

  Using IMC 0609, "Significance Determination Process," the team determined that this finding 1) was not a design deficiency or qualification deficiency; 2) did not represent an actual loss of safety function of a system; 3) did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time; 4) did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant; and 5) did not screen as potentially risk significant due to seismic, flooding, or a severe weather initiating event. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

  As part of the licensee's immediate corrective actions, all affected safety-related valves were scheduled to have their stem lubrication changed by the end of RFO10 (May 2005).

  This finding affected the cross-cutting area of Problem Identification and Resolution because licensee personnel failed to resolve a known condition adverse to quality in a timely manner. (Attachment 1, Item 1.5; NCV 05000440/2005003-08)

- Green. A finding of very low safety significance and an associated NCV of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was NRC-identified when licensee personnel failed to adhere to At-Risk-Change (ARC) procedures used for the modification of safety-related equipment without a completed and approved modification package.

  The team determined that the finding was of more than minor significance since the finding was associated with the configuration control attribute of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

Using IMC 0609, "Significance Determination Process," the team determined that this finding 1) was not a design deficiency or qualification deficiency; 2) did not represent an actual loss of safety function of a system; 3) did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time; 4) did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant; and 5) did not screen as potentially risk significant due to seismic, flooding, or a severe weather initiating event. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

As part of the licensee's immediate corrective actions, all modification work associated with the ARC process was suspended until all cognizant personnel were provided training.

This finding affected the cross-cutting area of Problem Identification and Resolution because licensee personnel failed to adequately address implementation of the ARC process until questioned by the team. (Attachment 1, Item 1.6; NCV 05000440/2005003-09)

- Green. A finding of very low safety significance and an associated NCV of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," was NRC-identified when licensee personnel failed to repair a long-standing Division 2 EDG lubricating oil cooler packing leak that was identified in November 2000, until May 2004 when the leak degraded and required emergent maintenance, rendering the EDG unavailable.

  The team determined that the finding was of more than minor significance since the finding was associated with the equipment performance attribute of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

  Using IMC 0609, "Significance Determination Process," the team determined that this finding 1) was not a design deficiency or qualification deficiency; 2) did not represent an actual loss of safety function of a system; 3) did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time; 4) did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant; and 5) did not screen as potentially risk significant due to seismic, flooding, or a severe weather initiating event. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

  As part of the licensee's immediate corrective actions the leak was repaired and the Division 2 EDG was returned to service.

  This finding affected the cross-cutting area of Problem Identification and Resolution because station personnel missed several opportunities to implement repairs. (Attachment 1, Item 1.9; NCV 05000440/2005003-12)

- Green. A finding of very low safety significance and an associated NCV of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action,” was NRC-identified when licensee personnel failed to correct an issue regarding the installation of scaffolding erected near safety-related equipment which did not meet the seismic bracing or clearance criteria of licensee procedures.

  The team determined that the finding was of more than minor significance since the finding was associated with the equipment performance and human performance attributes of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of equipment that respond to initiating events to prevent undesirable consequences.

  Using IMC 0609, “Significance Determination Process,” the team determined that this finding 1) was not a design deficiency or qualification deficiency; 2) did not represent an actual loss of safety function of a system; 3) did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time; 4) did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant; and 5) did not screen as potentially risk significant due to seismic, flooding, or a severe weather initiating event. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

  As part of the licensee’s immediate corrective actions, all scaffolding work was suspended and licensee personnel were required to obtain engineering approval of all scaffolding erections.

  This finding affected the cross-cutting area of Human Performance because licensee personnel failed to follow both the scaffolding erection procedure and the temporary alterations procedure. This finding also affected the cross-cutting area of Problem Identification and Resolution because a condition adverse to quality regarding scaffolding controls was not corrected, despite numerous opportunities.
  (Attachment 1, Item 1.10; NCV 2005003-13)

- Green. A finding of very low safety significance and an associated NCV of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," was NRC-identified when licensee personnel failed to adequately address a nonconforming condition in the design of the EDGs which made the EDGs vulnerable to damage in response to a loss of offsite power (LOOP) signal under certain scenarios.

  The team determined that the finding was of more than minor significance since the finding was associated with the design control and equipment performance attributes of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

  Using IMC 0609, “Significance Determination Process,” the team determined that this finding 1) was not a design deficiency or qualification deficiency confirmed not to result in a loss of function per Generic Letter 91-18; 2) did not represent an actual loss of safety function of a system; 3) did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time; 4) did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk

significant; and 5) did not screen as potentially risk significant due to seismic, flooding, or a severe weather initiating event. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

As part of the licensee's immediate corrective actions, an engineering change to modify the EDG start circuitry was initiated.

This finding affected the cross-cutting area of Problem Identification and Resolution because licensee personnel failed to adequately resolve a previously identified condition adverse to quality. (Attachment 1, Item 1.11; NCV 05000440/2005003-14)

- Green. A finding of very low safety significance and an associated NCV of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," was NRC-identified when licensee personnel failed to adequately review available industry operating experience information and failed to identify degraded oil reservoirs that could adversely impact the operability of both Emergency Closed Cooling Water (ECCW) pumps.

  The team determined that the finding was of more than minor significance since the finding was associated with the equipment performance attribute of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

  Using IMC 0609, "Significance Determination Process," the team determined that this finding 1) was not a design deficiency or qualification deficiency; 2) did not represent an actual loss of safety function of a system; 3) did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time; 4) did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant; and 5) did not screen as potentially risk significant due to seismic, flooding, or a severe weather initiating event. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

  As part of the licensee's immediate corrective actions, a walkdown of all potentially affected oil reservoirs was conducted and the reservoirs were verified to be able to properly provide makeup oil to all potentially affected pump bearings.

  This finding affected the cross-cutting area of Problem Identification and Resolution because licensee personnel failed to adequately resolve a known industry problem associated with improper reservoir installation.
  (Attachment 1, Item 1.12; NCV 05000440/2005003-15)

- Green. A finding of very low safety significance and an associated NCV of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," was NRC-identified when licensee personnel failed to initiate a condition report to correct a condition adverse to quality following an error in the performance of a safety-related breaker overcurrent device calibration procedure step.

The team determined that the finding was of more than minor significance because the ineffective implementation of procedure steps by maintenance, if left uncorrected, could become a more significant safety concern since safety-related equipment may not be properly tested, reassembled, or maintained.

Using IMC 0609, "Significance Determination Process," the team determined that this finding 1) was not a design deficiency or qualification deficiency; 2) did not represent an actual loss of safety function of a system; 3) did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time; 4) did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant; and 5) did not screen as potentially risk significant due to seismic, flooding, or a severe weather initiating event. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

As part of the licensee's immediate corrective actions, procedure steps were re-performed, and the breaker was re-tested satisfactorily.

This finding affected the cross-cutting area of Problem Identification and Resolution because licensee personnel failed to generate a condition report to identify a condition adverse to quality which adversely impacted the licensee's ability to take effective corrective actions to address the issue.
(Attachment 1, Item 2.2 NCV 05000440/2005003-19)

- Green. A finding of very low safety significance and an associated NCV of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was NRC-identified when licensee personnel failed to adhere to ARC procedures used for the modification of safety-related equipment and modified a portion of the Division 1, 2, and 3 EDG exhaust ventilation system without declaring the ventilation system unavailable, as required.

  The team determined that the finding was of more than minor significance since the finding was associated with the configuration control attribute of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

  Using IMC 0609, "Significance Determination Process," the team determined that this finding 1) was not a design deficiency or qualification deficiency; 2) did not represent an actual loss of safety function of a system; 3) did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time; 4) did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant; and 5) did not screen as potentially risk significant due to seismic, flooding, or a severe weather initiating event. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

As part of the licensee's immediate corrective actions the EDGs were declared inoperable until the modification was removed.

This finding affected the cross-cutting area of Human Performance since licensee personnel failed to adhere to the ARC procedure associated with the modification activities. (Attachment 1, Item 3.1; NCV 05000440/2005003-20)

- Green. A finding of very low safety significance and an associated NCV of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was self-revealed when licensee personnel improperly performed a procedure step for verification of the position of RCIC system electrical disconnects.

  The team determined that the finding was of more than minor significance since the finding was associated with the configuration control and human performance attributes of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

  Using IMC 0609, "Significance Determination Process," the team determined that this finding 1) was not a design deficiency or qualification deficiency; 2) did not represent an actual loss of safety function of a system; 3) did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time; 4) did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant; and 5) did not screen as potentially risk significant due to seismic, flooding, or a severe weather initiating event. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

  As part of the licensee's immediate corrective actions, the electrical disconnects were properly positioned.

  This finding affected the cross-cutting area of Human Performance because licensee personnel failed to adhere to procedure steps for aligning RCIC system electrical disconnects. (Attachment 1, Item 3.2; NCV 2005003-21)

- Green. A finding of very low safety significance and an associated NCV of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was self-revealed when maintenance personnel incorrectly performed a procedure step which verified that electrical jumpers had been removed from an electrical cabinet and as a result, inadvertently left an electrical jumper installed in the cabinet.

  The team determined that the finding was of more than minor significance since the finding was associated with the configuration control and human performance attributes of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

  Using IMC 0609, "Significance Determination Process," the team determined that this finding 1) was not a design deficiency or qualification deficiency; 2) did not represent an actual loss of safety function of a system; 3) did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time; 4) did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant; and 5) did not screen as potentially risk significant due to seismic, flooding, or a severe weather initiating event. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

As part of the licensee's immediate corrective actions, the electrical jumper that was inadvertently left in the affected electrical cabinet was removed.

This finding affected the cross-cutting area of Human Performance because licensee personnel performed an incorrect procedure step which verified that electrical jumpers had been removed from an electrical cabinet.
(Attachment 1, Item 3.3; NCV 05000440/2005003-22)

- Green. A finding of very low safety significance and an associated NCV of 10 CFR 50, Appendix B, Criterion III, "Design Control," was NRC-identified when licensee personnel failed to verify that the isolation function of the remote shutdown panel (RSP) emergency transfer switch was operable after a modification re-wired the switch and placed a previously unused set of contacts in the isolation circuit.

  The team determined that the finding was of more than minor significance since the finding was associated with the equipment performance and procedure quality attributes of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

  Using IMC 0609, "Significance Determination Process," Appendix F, "Fire Protection Significance Determination Process," the team reviewed the finding against the Phase 1 Qualitative Screening criteria. The severity of the deficiency was determined to have a low degradation rating, because the reliability of the system function impacted by the finding was not significant. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

  As part of the licensee's immediate corrective actions, licensee personnel verified the adequacy of the design modification through the performance of a suitable test.
  (Attachment 1, Item 4.1; NCV 05000440/2005003-23)

- Green. A finding of very low safety significance and an associated NCV of Perry Operating License Condition 2.C(6), "Fire Protection," was NRC-identified when licensee personnel revised the fire protection program to use manual actions for replacing fuses for safe post-fire shutdown, but did not adequately assess the ability to perform the actions and did not verify or validate that adequate time was available to perform the actions.

  The team determined that the finding was of more than minor significance since the finding was associated with the design control, equipment performance, and procedure quality attributes of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

Using IMC 0609, “Significance Determination Process,” Appendix F, "Fire Protection Significance Determination Process," the team reviewed the finding against the Phase 1 Qualitative Screening criteria. The Phase 1 screening determined that a Phase 2 evaluation was required because the severity of the deficiency was determined to have a moderate degradation rating. The Phase 2 evaluation determined this finding was of very low safety significance, because no potentially challenging fire scenarios were developed.

As part of the licensee’s immediate corrective actions, procedures were revised to add the affected fuses to the remote shutdown inventory and provide guidance regarding fuse replacement. (Attachment 1, Item 4.2; NCV 05000440/2005003-24)

- Green. A finding of very low safety significance and an associated NCV of 10 CFR 50, Appendix B, Criterion III, “Design Control,” was NRC-identified when licensee personnel failed to adequately evaluate the effect of water intrusion on the insulation composite installed in the EDG exhaust enclosure during modification activities.

  The team determined that the finding was of more than minor significance since the finding was associated with the design control attribute of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

  Using IMC 0609, “Significance Determination Process,” the team determined that this finding was a design deficiency or qualification deficiency confirmed not to result in a loss of safety function per Generic Letter 91-18. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

  As part of the licensee’s immediate corrective actions, engineering personnel re-calculated expected concrete temperatures, taking into account wetted insulation, and verified that the EDG exhaust enclosure remained operable. (Attachment 1, Item 4.3; NCV 05000440/2005003-25)

- Green. A finding of very low safety significance and an associated NCV of 10 CFR 50.65(a)(1), associated with the requirements for monitoring the effectiveness of maintenance, was identified when licensee personnel failed to establish appropriate goals and monitor the performance of the Division 2 EDG when the demonstration of effective control of performance of the EDG through appropriate preventive maintenance became invalid following a lube oil heat exchanger gasket failure.

  The team determined that the finding was of more than minor significance since the finding was associated with the equipment performance attribute of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

Using IMC 0609, “Significance Determination Process,” the team determined that this finding 1) was not a design deficiency or qualification deficiency; 2) did not represent an actual loss of safety function of a system; 3) did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time; 4) did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant; and 5) did not screen as potentially risk significant due to seismic, flooding, or a severe weather initiating event. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

As part of the licensee’s corrective actions, licensee personnel planned to discuss this issue with industry peers and determine whether the criteria used to categorize one of the EDG performance issues as a Maintenance Preventable Functional Failure was consistently understood and accepted. (Attachment 1, Item 6.1; NCV 05000440/2005003-28)

Cornerstone: Barrier Integrity

- Green. A finding of very low safety significance and an associated NCV of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action,” was NRC-identified when licensee personnel failed to promptly identify, and therefore correct in a timely manner, the condition of the reactor water cleanup (RWCU) primary containment isolation valves (PCIVs) inability to close when being secured from a normal RWCU valve lineup.

  The team determined that the finding was of more than minor significance since the finding was associated with the reactor coolant system (RCS) equipment and barrier performance attribute of the Barrier Integrity cornerstone and affected the cornerstone objective of providing reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events.

  Using IMC 0609, “Significance Determination Process,” the team determined that this finding 1) did not represent a degradation of the radiological barrier function of the control room, auxiliary building, spent fuel pool, or annulus exhaust gas treatment system; 2) did not represent a degradation of the barrier function of the control room against smoke or toxic gas; 3) did not represent an actual open pathway in the physical integrity of the containment; and 4) did not involve an actual reduction in the defense-in-depth for the atmospheric pressure control or the hydrogen control functions of containment. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

  To address this issue, licensee personnel initiated actions to improve the performance margin of the affected valves and review calculations to clarify the design and licensing basis.

  This finding affected the cross-cutting area of Problem Identification and Resolution because licensee personnel failed to correct the previously identified condition of the RWCU PCIVs inability to close under all operating conditions. (Attachment 1, Item 2.1; NCV 05000440/2005003-18)

- Green. A finding of very low safety significance and an associated NCV of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action,” was NRC-identified when licensee personnel failed to identify and correct numerous permanent structures (deck grating) that did not meet seismic separation distance requirements to the inside containment wall.

  The team determined that the finding was of more than minor significance since the finding was associated with the configuration control attribute of the Barrier Integrity cornerstone and affected the cornerstone objective of providing reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events.

  Using IMC 0609, “Significance Determination Process,” the team determined that this finding 1) did not represent a degradation of the radiological barrier function of the control room, auxiliary building, spent fuel pool, or annulus exhaust gas treatment system; 2) did not represent a degradation of the barrier function of the control room against smoke or toxic gas; 3) did not represent an actual open pathway in the physical integrity of the containment; and 4) did not involve an actual reduction in the defense-in-depth for the atmospheric pressure control or the hydrogen control functions of containment. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

  As part of the licensee’s immediate corrective actions all identified deficiencies were corrected and required seismic separation distances were restored. (Attachment 1, Item 1.2; NCV 05000440/2005003-05)

  The team also concluded that this finding affected the cross-cutting area of Problem Identification and Resolution because licensee personnel missed an opportunity to correct the condition which had occurred previously.

Cornerstone: Radiation Protection

- Green. A finding of very low safety significance was NRC-identified when licensee personnel failed to implement corrective actions to prevent recurrence of a significant condition adverse to quality in a timely manner. Specifically, corrective actions to investigate the organizational causes for elevated dose rates in Refueling Outage 9 (RFO9) failed to identify corrective actions to prevent recurrence. No violation of regulatory requirements occurred.

  The team determined that the finding was of more than minor significance because, if left uncorrected, the finding would become a more significant safety concern. Although not suited for SDP evaluation, the finding was determined to be of very low safety significance because no safety-related equipment was rendered inoperable as a result of the performance deficiency.

  This finding affected the cross-cutting area of Problem Identification and Resolution because the licensee failed to implement a corrective action to address a root cause of a condition adverse to quality. (Attachment 1, Item 1.8; FIN 05000440/2005003-11)

Cornerstone: Emergency Preparedness

- Severity Level IV. A finding of very low safety significance and an associated Severity Level IV NCV of 10 CFR 50.54(q) was NRC-identified when licensee personnel failed to obtain prior NRC approval for a change to the Perry Emergency Plan concerning emergency response organization (ERO) staffing and response timeliness. Because the issue affected the NRC's ability to perform its regulatory function, it was processed through the traditional enforcement process and evaluated using the SDP.

  Using IMC 0612, Appendix B, "Issue Dispositioning Screening," the inspectors determined that the finding was more than minor because it was associated with the ERO readiness and procedure quality attributes of the Emergency Preparedness cornerstone and affected the cornerstone objective of ensuring that the licensee is capable of implementing adequate measures to protect the health and safety of the public in the event of a radiological emergency.

  The finding was considered to be of only very low safety significance since the period of vulnerability to the issue was short.

  As part of the licensee's corrective actions, the issue was entered in the licensee's corrective action program for resolution as CR 05-03271.
  (Attachment 1, Item 5.1; NCV 05000440/2005003-26)

- Green. A finding of very low safety significance and an associated NCV of 10 CFR 50.47(b)(4) was NRC-identified when a change was made that adversely impacted Emergency Action Level (EAL) implementation. Specifically, a Security Plan revision implemented on November 8, 2005, eliminated terms from the Security Plan and Security Event Checklists, which adversely affected EAL classifications.

  The team determined that the finding was of more than minor significance since the finding was associated with the ERO performance and procedure quality attributes of the Emergency Preparedness cornerstone and affected the cornerstone objective of ensuring that the licensee is capable of implementing adequate measures to protect the health and safety of the public in the event of a radiological emergency.

  Using IMC 0609, "Significance Determination Process," Appendix B, "Emergency Preparedness Significance Determination Process," and Sheet 1, "Emergency Preparedness Significance Determination Process - Failure to Comply," the team determined that this finding involved a planning standard problem, involved a risk-significant planning standard (RSPS) problem, did not result in a planning standard function failure, and did not result in a RSPS degraded function. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

  As part of the licensee's immediate corrective actions, the licensee issued Security Operations Directive 05-0005 to require security personnel to use appropriate terms to communicate event information to the shift manager.
  (Attachment 1, Item 5.2; NCV 05000440/2005003-27)

B. Licensee-Identified Violations

Violations of very low safety significance, which were identified by the licensee, have been reviewed by the team. Corrective actions taken or planned by the licensee have been entered into the licensee’s CAP. The violations and corrective action tracking numbers are listed in Section 7 of this report.

REPORT DETAILS

1.0 Performance Background

As discussed in the Perry Annual Assessment Letter dated March 4, 2004, plant performance was categorized within the Degraded Cornerstone column of the NRC's Action Matrix based on two White findings in the Mitigating Systems cornerstone. An additional White finding in the Mitigating Systems cornerstone was subsequently identified and documented by letter dated March 12, 2004.

The first finding involved the failure of the high pressure core spray (HPCS) pump to start during routine surveillance testing on October 23, 2002. An apparent violation of Technical Specification (TS) 5.4 for an inadequate breaker maintenance procedure was identified in IR 05000440/2003008. This performance issue was characterized as White in the NRC's final significance determination letter dated March 4, 2003. A supplemental inspection was performed in accordance with IP 95001 for the White finding and significant deficiencies were identified with regard to the licensee's extent of condition evaluation. Inspection Procedure 95001 was re-performed and the results of that inspection were documented in IR 05000440/2003012 which determined that the extent of condition reviews were adequate.

The second finding involved air-binding of the LPCS/RHR 'A' waterleg pump on August 14, 2003. A special inspection was performed for this issue and the results were documented in IR 05000440/2003009. An apparent violation of TS 5.4 for an inadequate venting procedure was identified in IR 05000440/2003010. This performance issue was characterized as White in the NRC's final significance determination letter dated March 12, 2004.

The third finding involved the failure of the 'A' ESW pump, caused by an inadequate maintenance procedure for assembling the pump coupling which contributed to the failure of the pump on September 1, 2003. An apparent violation of TS 5.4 was documented in IR 05000440/2003006. This performance issue was characterized as White in the NRC's final significance determination letter dated January 28, 2004.

As documented in IP 95002 Supplemental Inspection Report 05000440/2004008, dated August 5, 2004, which reviewed the licensee's actions to address these issues, the NRC concluded that the corrective actions to prevent recurrence of a significant condition adverse to quality (SCAQ) were inadequate. Specifically, the same ESW pump coupling that failed on September 1, 2003, failed again on May 21, 2004. This resulted in the ESW pump White finding remaining open.

As a result, Perry entered the Multiple/Repetitive Degraded Cornerstone column for Mitigating Systems in the Reactor Safety strategic performance area for having two White inputs for five consecutive quarters. Specifically, for the third quarter of 2004, the waterleg pump finding remained open a fourth quarter while the ESW pump finding was carried open into a fifth quarter as a result of the findings of the IP 95002 supplemental inspection.

In the NRC's assessment follow-up letter dated August 12, 2004, the licensee was informed of the decision to conduct the IP 95003 supplemental inspection. The intent of the IP 95003 inspection was to allow the NRC to obtain a comprehensive understanding of the depth and breadth of safety, organizational, and performance issues at Perry.

By letter dated September 30, 2004, FirstEnergy advised the NRC that prior to receiving the NRC's August 12, 2004, Assessment Followup Letter in which the PNPP was identified to have transitioned into the Multiple/Repetitive Degraded Cornerstone column of the NRC's Action Matrix, actions were underway to improve plant performance. To facilitate these performance improvements, FirstEnergy developed the Perry Performance Improvement Initiative (PII).

As prescribed by IP 95003, the scope of NRC inspection activities at Perry included the assessment of performance in the Reactor Safety strategic performance area, including the inspection of key attributes such as design, human performance, procedure quality, equipment performance, configuration control, and emergency response organization readiness. Also, the IP 95003 inspection reviewed the control systems for identifying, assessing, and correcting performance deficiencies to evaluate whether programs are sufficient to prevent a further decline in performance that could result in unsafe operation. During this inspection, the team also reviewed the licensee's actions to address the deficiencies identified during the previous IP 95002 inspection as well as the scope and implementation of the Perry PII.

2.0 Review of Licensee Program for Identifying, Assessing, and Correcting Performance Deficiencies

2.1 Background

NRC inspections have identified significant findings associated with the licensee's CAP.

The first finding involved the failure of the HPCS pump to start during routine surveillance testing on October 23, 2002. A supplemental inspection was performed in accordance with IP 95001 for this White finding and significant deficiencies were identified with regard to the extent of condition evaluation. Subsequently, IP 95001 was re-performed and the results of that inspection were documented in IR 05000440/2003012 which determined that the extent of condition reviews were adequate.

The second finding involved the failure of ESW pump 'A,' caused by an inadequate maintenance procedure for assembling the pump coupling which contributed to the failure of the pump on September 1, 2003. As documented in IP 95002 supplemental IR 05000440/2004008, the NRC concluded that the corrective actions to prevent recurrence of a SCAQ were inadequate. Specifically, the same ESW pump coupling that failed on September 1, 2003, failed again on May 21, 2004. This resulted in the ESW pump White finding remaining open.

Additional problems with the CAP, which resulted in the NRC identification of a substantive cross-cutting issue in the area of problem identification and resolution, were discussed in the Mid-Cycle Assessment Letter to the licensee, dated August 30, 2004; and the End of Cycle Assessment Letter to the licensee, dated March 4, 2005.

With consideration of these problems, the NRC reviewed the licensee’s CAP using the guidance of IP 95003 to evaluate the licensee’s systems for identifying, assessing, and correcting performance deficiencies and determine whether the program was sufficient to prevent further performance degradations that could result in unsafe operation. This evaluation focused on the following areas:

- Licensee evaluations of, and corrective actions to, significant performance deficiencies (such as White inspection findings or other SCAQs),
- Effectiveness of audits and assessments performed by the quality assurance group, line organizations, and external organizations,
- Process for allocating resources and management of corrective action backlogs and correction of operator workarounds,
- Licensee performance goals and congruence with corrective actions needed to address the documented performance issues,
- Employee willingness to use and effectiveness of the employee concerns program, and
- Effectiveness of the licensee’s use of industry information (operating experience) for previously documented performance issues.

In addition to this specific review of the CAP, the other phases of the IP 95003 inspection reviewed CAP aspects related to the engineering, operations, maintenance, and emergency preparedness areas.

2.2 Review of Significant Performance Deficiencies

a. Inspection Scope

The team conducted a review of the licensee’s condition reporting system and related programs focusing on evaluating the licensee’s ability to identify, assess, and effectively correct significant performance deficiencies. With regard to the review of the licensee’s corrective actions to address significant performance deficiencies, the team reviewed the licensee's actions to address the deficiencies identified during the IP 95002 inspection. In particular, the team reviewed the licensee's root cause evaluation and corrective actions to address weaknesses in the areas of procedure adequacy, procedure adherence, and training that were documented in IR 05000440/2004008; as well as the licensee's problem identification, root cause review, and corrective actions to address the repetitive ESW pump coupling failures. In addition, the team reviewed licensee actions to address identified program performance issues. The team’s observations are divided into programmatic issues, program implementation issues, and IP 95002 review issues.

b. Observations and Findings

2.2.1 Corrective Action Program (CAP) Programmatic Review and Results

The team concluded that the CAP was adequate to meet the requirements of 10 CFR 50, Appendix B. However, the team also concluded that the program relied on broad interpretations and aggressive implementation to be fully effective. The program was found to contain mention of and reference to many desirable attributes, including management discretion and flexibility to allow conservative decision-making for the resolution of identified problems. However, this flexibility has not been effectively used to address problems.

Numerous findings and observations related to this area were identified during the inspection, particularly in the identification and implementation of corrective actions. These findings were identified in all focus areas.

Overall, the team concluded that there has been no substantial improvement in the licensee's implementation of the CAP since Perry entered the Multiple/Repetitive Degraded Cornerstone column of the NRC's Action Matrix.

As amplified in the following sections, a number of programmatic issues were identified that have resulted in the observed CAP problems. For example, the team identified a relatively high threshold for classifying deficiencies as significant conditions adverse to quality (SCAQs). As a result, few issues received root cause evaluations. Weaknesses in the analytical methods themselves were also identified. In addition, for the conditions that were identified as requiring a root cause evaluation, the team identified that the program required only minimal qualification requirements for root cause evaluators, lacked guidance on evaluator independence, and did not require multi-disciplinary teams. The team also identified weaknesses in the trending of problems, which has hindered the licensee's ability to correct problems at an early stage before they become more significant. Finally, effectiveness review weaknesses were also identified.

Deficiency Classification and Resolution

To prioritize identified issues, the licensee utilized three significance levels and provided general examples to assist in the assignment of an appropriate significance level. NOP-LP-2001, "Condition Report Process," was the primary guidance document for the CAP. Attachment 1, "Condition Report Category Descriptions," of NOP-LP-2001 defined the term SCAQ and listed five subcategories for assigning SCAQs. The same subcategories with different examples were provided for conditions adverse to quality (CAQs) and conditions not adverse to quality (NCAQs). These examples provided substantial latitude in the determination of significance. From interviews and other discussions with licensee personnel, and from the relatively infrequent determination of an SCAQ; five total in 2004, the team concluded that significant problems were narrowly defined and were strictly event-based or outcome-based. In general, if a significant consequence resulted from an event, then the matter was treated as significant; however, if there was no significant adverse consequence, the matter was unlikely to be viewed as significant. This approach had the potential to allow a significant issue to be considered as a less significant matter, resulting in a missed opportunity to proactively evaluate and address a problem before it resulted in a more significant event. In addition, based on the review of SCAQs and CAQs, human performance and organizational issues were much less likely than equipment issues to be treated as SCAQs.

During the inspection, the team identified a steady decline in the number of root cause evaluations and condition reports (CRs) categorized as SCAQs. In particular, since 2002 when a total of 47 root cause evaluations were performed of which 25 were associated with identified SCAQs; that number declined steadily to 25 total root cause evaluations with 17 associated SCAQs in 2003; and most recently to 9 total root cause evaluations with only 5 SCAQs in calendar year 2004. This decline in the number of root cause evaluations and SCAQs occurred although plant performance had also steadily declined from 2002 when Perry was categorized within the Regulatory Response column of the NRC's Action Matrix, to 2003 when Perry was categorized within the Degraded Cornerstone column of the Action Matrix, until most recently in 2004 when Perry was categorized within the Multiple/Repetitive Degraded Cornerstone column of the Action Matrix.

In addition, NOP-LP-2001 required that any request for a downgrade in category or evaluation method be documented on Condition Report Downgrade Form NOP-CB-2001-11 and be submitted to the licensee's Management Review Board for approval. However, the team identified that a de facto downgrade could occur when a CR was closed to another CR. For example, CR 03-02073 identified that a worker received an unplanned exposure in excess of the authorized administrative limit during work in the RWCU heat exchanger room. The original corrective actions were determined to be ineffective. Condition Report 04-05130 was generated to assess the ineffective corrective actions. The team identified that CR 04-05130 was only categorized as "NF," a NCAQ-fix, although the original CR was categorized as an SCAQ. The team noted that the licensee's IP 95003 support team had identified the same concern prior to the NRC's team arriving on the site and re-categorized the CR as a "CF," a CAQ-fix. By categorizing the CR as a NCAQ-fix or a CAQ-fix, the requirements for extent of cause and extent of condition, along with prevention of recurrence, did not apply, although warranted based upon the significance of the originally identified issue.

As another example, the team identified that CR 03-06778, "Safety Culture Assessment Attribute 5 Rated Yellow," was categorized a NF. This CR documented that Perry's Safety Culture Assessment Criteria related to Nuclear professionalism, Attribute 5, "Procedural Compliance," was rated Yellow (third lowest rating out of four). This rating indicated that individuals were generally complying with procedures; however, several examples of procedural non-compliance were identified. The examples included: 1.) CR 03-04912: While performing restoration activities from a LOOP, Division 1 EDG tripped on reverse power. Steps in SOI were inappropriately identified and diesel operability was not verified. 2.) CR 03-06213: ESW was lined to the swale using an incorrect section of the SOI. 3.) CR 03-04280: LPCS was started using the incorrect SOI. 4.) CR 03-05927: NOP-ER-3001, "Problem Solving and Decision Making Process," is not consistently followed during the performance of troubleshooting activities. The CR also pointed out that procedural compliance had been repeatedly addressed in Quality Assurance assessments and was identified as a continuing issue in the Perry self assessment related to the Davis-Besse head event. The team was concerned that the CR addressed issues related to four other CRs, one SCAQ, two CAQs, and the other a NR, and their effect on the safety culture attribute of “procedural compliance,” yet it was categorized as not important to quality, fix only without further evaluation.

Analytical Methods for Evaluating Issues

During the inspection, the team determined that only SCAQs required root cause evaluations. In addition, a root cause evaluation only required one root cause analysis method, as selected by the root cause analyst. This practice provided only the minimal necessary assurance that an identified problem would be thoroughly and adequately reviewed and that all root and contributing causes would be identified. In addition, NOP-LP-2001 stated, in part, that “Generic implications are performed for Root Cause and Apparent Cause Investigations in accordance with NOBP-LP-2016, Generic Implications.” Also, NOBP-LP-2016 stated, in part, that “The extent of cause is performed on SCAQ root cause(s) only.” Therefore, extent of cause reviews were not required for CAQs, and NCAQs, regardless of the evaluation method. Further, extent of cause reviews were not required for contributing causes at any CR level. The team concluded that corrective actions to prevent the recurrence of problems were only required for a small sub-set of causes which provided only the minimum assurance necessary to ensure that problems did not recur.

The team identified examples where the extent of condition or extent of cause reviews were narrowly focused, resulting in continued conditions adverse to quality or the incomplete evaluation of consequences. The following two examples were identified:

- In October 2002, the HPCS pump failed to start during testing. Licensee personnel identified that a cell switch used to determine whether the breaker was fully inserted into the cubicle had not been properly aligned. Licensee personnel also determined that the procedures used to align the cell switches did not contain adequate alignment instructions. As discussed in IR 05000440/2003008, the NRC identified that licensee personnel had limited planned corrective actions to only cell switches in similarly sized breaker applications, although an identical cell switch design was used in breaker applications of different sizes. After licensee personnel expanded the scope of their inspections to include these other potentially affected breakers, several additional switches were identified to require cell switch adjustment to ensure continued operability.

- On August 14, 2003, following a LOOP event, the LPCS/RHR 'A' waterleg (keepfill) pump was determined to be air-bound, rendering the LPCS system and 'A' RHR sub-system inoperable. Licensee personnel successfully vented the waterleg pump casing within a few hours and returned the LPCS system and 'A' RHR sub-system to an operable status. However, the licensee restarted the plant without completely understanding the source of the air. The NRC performed a special inspection documented in IR 05000440/2003009 to understand the circumstances leading to the failure. In September 2003, licensee personnel identified a high point vent valve that had been omitted from their surveillance and operating procedures. Further investigation revealed another vent valve in the system that had been inadvertently omitted. Venting of these points released unquantified amounts of air. Licensee personnel determined that the failure to vent the system left it susceptible to failures similar to the failure experienced on August 14, 2003. In 2004, as a result of external operating experience, licensee personnel identified additional vent valves in the RHR system associated with abandoned steam condensing mode piping interfaces with RCIC piping.

Training and Independence of Evaluators

Required qualifications for root cause analysts, apparent cause evaluators, and other participants in CR evaluations included training and completion of Job Familiarization Guidelines (JFGs). The team identified that minimum root cause analyst qualification requirements consisted of a 2-day training course in one root cause technique. The team concluded that the requirement for only 2 days of training in one root cause analysis method represented a vulnerability in the licensee's CAP for ensuring that proper root cause evaluations would be conducted.

The team also identified four references in CAP documents where independence was allowed ("may") or encouraged ("should"); however, no requirements for independent evaluations for any CR level were identified. In reviewing assignments made by the Management Review Board, the team observed that many CRs were re-assigned to the areas where the problems originated. The team also identified that there was no requirement for investigative teams for any CR level of significance or evaluation method. The team concluded that the absence of guidance or requirements for the formation of multi-disciplinary teams to review significant events was a programmatic vulnerability. The team noted that root cause evaluations had begun to receive peer reviews, and reviews were also accomplished by the Corrective Action Review Board (CARB), an Engineering Review Board, and a corrective action closure board. However, these reviews were after-the-fact and did not provide the same level of independence as an independent, inter-disciplinary initial evaluation. For example, in October 2002, CR 02-03972 was generated to document a failure of the HPCS pump. On March 19, 2003, the Site Vice President directed that a CR (CR 03-03196) be generated to evaluate the timeliness of corrective actions to address this issue as well as the overall effectiveness of the organization since 5 months had passed following the failure of this safety-related system and long-term corrective actions had not yet been implemented. An individual, not qualified in root cause techniques, had been assigned to perform the root cause evaluation for CR 02-03972 and implement appropriate corrective actions. Subsequently, this same individual was assigned to perform the root cause evaluation for CR 03-03196 and determine whether the root cause evaluation associated with CR 02-03972 was adequate and whether corrective actions were developed and implemented in a timely manner.

Trending of Issues and Causes

During the inspection, the team determined that trending was inconsistently performed, and that even if performed, did not include all performance deficiencies since these deficiencies were not consistently captured in CRs in the CAP. For example, the team identified that MOV issues such as negative performance trends and low thrust margins had not been entered into the CAP.

During the inspection, the team also identified that no required action thresholds were defined by the CAP to escalate categories or evaluation methods. Instead, the licensee depended upon the judgment of reviewers and “cognitive trending” rather than operational definitions of “multiple,” “repeat” and “adverse trend” to escalate an issue. The team concluded that this programmatic practice represented a vulnerability in the CAP for the identification of adverse trends and the performance of root cause evaluations.

Effectiveness Reviews

The team reviewed various CAP documents which contained guidance for the identification and implementation of corrective actions as well as for the performance of effectiveness reviews to ensure that corrective actions were effectively implemented and had adequately addressed the identified problem. The following vulnerabilities were identified in which the effectiveness of corrective actions may not be assured.

- Corrective actions were not required to be specifically validated against the root cause. As a result, the effectiveness of corrective action(s) to address the root cause was not assured.

- The prescribed 6 month waiting period before verifying the effectiveness of corrective actions may not always be appropriate, depending upon the specific issue and circumstances.

2.2.2 Problem Identification and Resolution Issues

In the review of the implementation of the CAP, the team identified numerous examples where the CAP was not adequately implemented. The team identified that the ineffective implementation of the CAP had resulted in a number of adverse impacts including repetitive failures of plant components, as well as the recurrence of significant issues. For example, as discussed in IR 05000440/2004008, the 'A' ESW pump coupling that failed on September 1, 2003, failed again on May 21, 2004. Also, licensee personnel failed to properly address operating experience information available since 1994 regarding the inappropriate use of “Never-Seez” as a MOV stem lubricant, resulting in a number of valves failing to meet surveillance test criteria or degraded valve performance. In addition to the ESW pump and MOV failures, other repetitive failures resulting in less significant consequences were identified. For example, a hydramotor valve actuator failure resulted in a safety system functional failure. Subsequently, licensee personnel identified an adverse trend with 17 hydramotor failures in the last 7 years. In addition, licensee personnel determined that previous root cause evaluations typically failed to identify a root cause and failed to adequately consider all available industry operating experience. Also, fuel failures had been identified in 9 of the previous 10 operating cycles. The licensee had attributed a number of these failures to foreign material induced fretting damage. Previous failures required plant shutdowns to remove fuel bundles to address this issue. However, corrective actions to address the root cause of the foreign material issue were implemented only recently.

Findings Related to Inadequate Identification and Implementation of Corrective Actions

Numerous problems associated with the CAP, particularly in the identification of root cause(s) and the implementation of adequate corrective actions, have adversely impacted a number of areas of plant performance.

- During this inspection and as detailed in Attachment 1 of this report, the team identified that the licensee's corrective actions to address concerns regarding SLC system relief valve setpoints and design assumptions were inadequate. (Attachment 1, Item 1.1)

- During this inspection and as detailed in Attachment 1 of this report, the team identified that the licensee's corrective actions to address a nonconforming condition in the design of the EDGs was inadequate. (Attachment 1, Item 1.11)

- As discussed in IR 05000440/2005002, on January 18, 2005, licensee personnel failed to take prompt action to address erroneous and unexplainable data recorded during 'B' ECCW pump and valve operability testing.

- As discussed in IR 05000440/2005005, licensee personnel failed to incorporate industry operating experience into preventative maintenance (PM) activities which resulted in a trip of the 'A' reactor recirculation pump low frequency motor generator and a subsequent manual scram on December 23, 2004.

- During this inspection and as detailed in Attachment 1 of this report, the team identified that licensee personnel failed to properly address operating experience and prevent the oil feed supply from protruding into the oil reservoir housing of oilers associated with safety-related equipment. As a result, Division 1 and Division 2 of the ECCW system were declared inoperable. (Attachment 1, Item 1.12)

- During this inspection and as detailed in Attachment 1 of this report, the team identified a number of examples in which grating was touching or in close proximity to the containment liner, potentially challenging the integrity of the liner during a seismic event. In addition, following the implementation of corrective actions to address this issue, including an extent of condition review, the team identified additional examples in which clearance requirements between structures and the containment liner were not met. (Attachment 1, Item 1.2)

- During this inspection and as detailed in Attachment 1 of this report, improper bolts were installed in a drywell supply fan resulting in a failure; a repeat event documented in CR 99-00718. (Attachment 1, Item 1.3)

- During this inspection and as detailed in Attachment 1 of this report, the team identified that licensee personnel failed to include appropriate Quality Control

(QC) hold points in ESW pump coupling assembly steps, although this issue had been previously identified as a NCV in IR 05000440/2004008. (Attachment 1, Item 1.14)

- During this inspection and as detailed in Attachment 1 of this report, the team identified that licensee personnel failed to implement adequate corrective actions to address air-binding of the LPCS/RHR 'A' waterleg pump and failed to identify an additional air void that could have affected the RCIC system until operating experience was received and reviewed. (Attachment 1, Item 1.4)

- During this inspection and as detailed in Attachment 1 of this report, the team identified that licensee personnel failed to implement adequate corrective actions in a timely manner to address the inappropriate use of “Never-Seez” lubricant in safety-related MOV applications. (Attachment 1, Item 1.5)

- During this inspection and as detailed in Attachment 1 of this report, the team identified that licensee personnel inappropriately considered the ARC design procedure, NOP-CC-2003, to be satisfied through “intent” although the EDG missile barrier was not considered out-of-service as required by NOP-CC- 2003 while the missile barrier was in the process of being modified. (Attachment 1, Item 1.6)

- During this inspection and as detailed in Attachment 1 of this report, the team identified repetitive problems in the control of scaffolding erected in the vicinity of safety-related equipment. During this inspection, the team identified that scaffolding erected in the Division 1 EDG room was not installed in accordance with scaffold erection procedure GCI-0016, nor was it evaluated by engineering as required. (Attachment 1, Item 1.10)

- During this inspection and as detailed in Attachment 1 of this report, the team identified that corrective actions to address “management failures in the identification of problems with reactivity control systems” as a root cause for unexpected control rod movement failed to adequately address the problem. (Attachment 1, Item 1.7)

- During this inspection and as detailed in Attachment 1 of this report, the team identified that licensee personnel failed to establish corrective actions in a timely manner to address deviations from training during stressful times. (Attachment 1, Item 1.13)

- During this inspection and as detailed in Attachment 1 of this report, the team identified that the corrective actions implemented to investigate the organizational causes for elevated dose rates in Refueling Outage 9 (RFO9) failed to identify specific preventative actions to address the identified root cause. (Attachment 1, Item 1.8)

- During this inspection and as detailed in Attachment 1 of this report, the team identified that licensee corrective actions to address a Division 2 EDG lube oil leak were untimely and adversely impacted the reliability of the EDG. (Attachment 1, Item 1.9)

Findings Related to the Identification of Issues

The following issues related to the identification of problems were identified by the team:

- During this inspection and as detailed in Attachment 1 of this report, the team identified that licensee personnel failed to recognize and correct the inability of RWCU PCIVs to close under all plant operating conditions. (Attachment 1, Item 2.1)

- During this inspection and as detailed in Attachment 1 of this report, the team identified that technicians failed to adhere to testing procedures and attached a lead to an incorrect location. Subsequently, licensee personnel failed to initiate a CR, as required, to identify that they had improperly installed the lead during testing. (Attachment 1, Item 2.2)

In addition, the team identified numerous condition reports that documented inadequate or inappropriate corrective actions; however, in no cases were condition reports initiated to review why the organization had proposed, approved, and implemented inadequate or inappropriate corrective actions. The only actions taken were to evaluate new or revised corrective actions to address the initial deficiency. This was considered a program implementation weakness in that the organization appeared to not recognize implementation of inadequate corrective actions as a deficiency.

2.2.3 Perry IP 95002 Inspection Review

Background

As documented in NRC inspection report 05000440/2004008, dated August 5, 2004, the NRC previously conducted a supplemental inspection in accordance with IP 95002, “Inspection For One Degraded Cornerstone Or Any Three White Inputs In A Strategic Performance Area,” at the PNPP.

The NRC performed the supplemental inspection to assess the licensee’s evaluation of three White findings in the Mitigating Systems cornerstone. The inspection was conducted in accordance with IP 95002, and evaluated the licensee’s actions to address these White findings. The first White finding involved the failure of the HPCS pump breaker to close during testing. The second White finding concerned air-binding of the LPCS/RHR 'A' waterleg pump. The third White finding involved the failure of a coupling sleeve that joined the ESW pump 'A' shaft segments together.

The purpose of the supplemental inspection was to provide assurance that the root and contributing causes for the three White findings and for the overall performance issues which resulted in the Degraded Cornerstone were understood; independently assess the extent of condition and generic implications; and provide assurance that the corrective actions were sufficient to prevent recurrence.

Following this inspection, the NRC concluded that the corrective actions to prevent recurrence of a SCAQ were inadequate. Specifically, the ESW pump coupling that failed on September 1, 2003, failed again on May 21, 2004. This was considered a significant issue with the licensee's evaluation and resulted in the ESW pump White finding, which contributed to the Degraded Cornerstone, remaining open. The NRC considered this significant in that it demonstrated an inability of the staff to develop adequate corrective actions to preclude a repeat occurrence that ultimately affected the availability and reliability of equipment in the Mitigating Systems cornerstone.

In addition, the identification of three findings during the NRC's independent root cause review confirmed the need for a thorough assessment of the common causes of inadequate procedures, inadequate procedure adherence, and ineffective training for two of the three White findings.

Summary of Results

During this inspection, the team reviewed the licensee's actions to address the deficiencies identified during the previous IP 95002 inspection. In particular, the team reviewed the licensee's corrective actions to address the areas of procedure adequacy, procedure adherence, and training identified in the previous IP 95002 inspection; as well as the problem identification, root cause review, and corrective actions to address the repetitive ESW pump coupling failures.

Based on this review, the team concluded the following:

- Although progress on maintenance procedure improvements was adequate, a plan to complete the procedure upgrade process was needed;

- Design changes developed and installed on the ESW pumps provided adequate assurance that future coupling failures would be prevented;

- Corrective actions to improve procedure use and adherence have not been fully effective;

- Corrective actions to address the management and organizational issues associated with the second ESW pump failure have not been fully effective; and

- Corrective actions to address training effectiveness have not been fully effective.

These conclusions were based upon the following information gathered to address the applicable specific questions prescribed in Inspection Procedure 95002.

Review of Common Cause Regarding Procedure Adequacy, Adherence, and Training

Corrective Actions

a. *Determine that appropriate corrective actions are specified for each root cause and contributing cause or that there is an evaluation that no actions are necessary.*

IR 05000440/2004008 included three NCVs which the team reviewed.

Review of NCV 05000440/2004008-01: Failure to Follow Quality Control Requirements of American National Standards Institute (ANSI) N45.2.8 -1975.

As discussed in IR 05000440/2004008, a finding of very low safety significance was identified when licensee personnel failed to establish quality control requirements described in ANSI N45.2.8-1975 for the re-assembly of the 'A' ESW pump coupling in 1997. The primary cause of this finding was a general lack of knowledge of quality control requirements.

A review of the corrective actions implemented by the licensee indicated that, although some actions to address QC concerns had been identified and implemented, specific corrective actions to address the subject NCV had not been implemented. Although specifically cited for not including QC inspections of coupling re-assembly, a review of two work packages regarding ESW pump re-assembly revealed that no QC inspections were required during coupling re-assembly.

As a result, and as discussed in Attachment 1 to the report, a finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action,” was identified when licensee personnel failed to correct a CAQ identified in IR 05000440/2004008 regarding a NCV for the failure to properly inspect the re-assembly of ESW pump couplings. (Attachment 1, Item 1.14)

Additional review of the QC program identified the following weaknesses that potentially impeded the licensee’s ability to meet regulatory commitments.

- The QC program only required inspections for code-required special processes such as welding. As a result, a significant modification to a structure, system, or component (SSC) could be completed without any required QC inspections to verify the adequacy of the work. The licensee committed to ANSI N45.2.8-1975 in their Quality Assurance Program Manual which required that inspection activities be performed in a systematic manner to assure surveillance throughout the installation process. However, the licensee’s implementing instruction did not include this requirement.

- During the observation of ESW pump maintenance activities, the team noted that parts used for re-assembly were separated from the documentation related to the part. Licensee procedures required that certifications remain with parts until installation. While in violation of the procedure and therefore regulatory requirements, the team was unaware of any instance where an improper part was installed. Therefore, the team considered this to be a minor violation.

Review of NCV 05000440/2004008-02: Missed Opportunities to Identify Missing Vent Valve in the Feedwater Leakage Control System.

As discussed in IR 05000440/2004008, a finding of very low safety significance was identified when licensee personnel failed to identify several missed opportunities to identify inadequate venting of safety-related systems. These missed opportunities included biennial reviews of procedures conducted between 1985 and 1995, a design review of the RHR system conducted in 1996, and venting issues that occurred in RFO9 (April 5 through May 31, 2004). Licensee personnel generated CR 04-03105 to identify this issue for resolution in their CAP. The primary cause of the failure to identify these missed opportunities was a weakness in the ability to conduct a thorough root cause evaluation. Corrective actions to address this issue included improvements in the root cause analyst training process as well as the root cause process to ensure better treatment of missed opportunities to identify SCAQs.

During this inspection, the team reviewed the program changes and root causes completed since implementation of this corrective action. The team concluded that the training had been effective in including evaluation of prior opportunities for discovery in root cause analyses.

Review of NCV 05000440/2004008-03: Training Effectiveness Not Addressed in Root Cause Report for CRs 02-03972, 03-05065, and 03-04912.

As discussed in IR 05000440/2004008, a finding of very low safety significance was identified when licensee personnel failed to recognize whether training was effective for the root cause evaluations for CR 02-03972, CR 03-05065, and CR 03-04912. Licensee personnel initiated CR 04-03020 to identify this issue for resolution in their CAP. However, the CR narrowed the scope to a failure to evaluate training effectiveness as part of the root cause process. Corrective actions addressed the deficiencies in the root cause process, but the underlying issues of training ineffectiveness were not addressed in a timely manner.

As a result, and as detailed in Attachment 1 to this report, a finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action,” was identified when licensee personnel failed to correct in a timely manner a CAQ regarding operator deviation from training during stressful situations. (Attachment 1, Item 1.13)

b. *Determine that the corrective actions have been prioritized with consideration of the risk significance and regulatory compliance.*

The team reviewed the priority assigned to the identification and implementation of corrective actions to address the NCVs identified in IR 05000440/2004008.

The team concluded that the prioritization of corrective actions associated with the less than thorough root cause analyses were adequate since corrective actions were implemented prior to the completion of any additional root cause evaluations.

The team concluded that the timeliness of the resolution of concerns associated with the omission of QC hold points during ESW pump coupling re-assembly activities was adequate.

However, as discussed above and detailed in Attachment 1 to this report, a finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," was identified when licensee personnel failed to adequately prioritize the resolution of issues associated with training effectiveness which resulted in the untimely identification and implementation of those corrective actions. (Attachment 1, Item 1.13)

c. *Determine that a schedule has been established for implementing and completing the corrective actions*.

The team determined that licensee personnel had not established a specific schedule for implementing and completing the corrective actions to address procedure adequacy, procedure adherence, and training issues identified in the IP 95002 inspection report. However, the Perry PII schedule included elements associated with procedure adequacy, procedure adherence, and training.

d. *Determine that quantitative or qualitative measures of success have been developed for determining the effectiveness of the corrective actions to prevent recurrence*.

The team determined that licensee personnel had not established specific quantitative or qualitative measures of success for determining the effectiveness of the corrective actions to prevent recurrence for the procedure adequacy, procedure adherence, and training issues identified in the IP 95002 inspection report. However, the Perry PII included quantitative and qualitative measures of success for determining the effectiveness of the corrective actions associated with procedure adequacy, procedure adherence, and training.

<u>Independent Assessment of Extent of Condition and Extent of Cause</u>

a. *Perform a focused inspection to independently assess the validity of the licensee's conclusions regarding the extent of condition and extent of cause of the issues.*

The Perry PII identified widespread and pervasive issues in the areas of procedure quality, procedure use and adherence, management decision-making, human performance, vendor quality, and problem identification; all of which were contributing factors to the White findings reviewed during the IP 95002 inspection.

During this inspection, the team identified additional issues in the same areas as those identified in the Perry PII. These issues are included and discussed throughout this report and validated the licensee's conclusions regarding the extent of condition and extent of cause of the procedure adequacy, procedure adherence, and training issues.

Review of Repetitive ESW Pump Failures

Problem Identification

a. *Determine that the evaluation identifies who (i.e., licensee, self-revealing, or NRC), and under what conditions the issue was identified.*

The May 21, 2004, 'A' ESW pump coupling failure was a self-revealing event.

b. *Determine that the evaluation documents how long the issue existed and prior opportunities for identification.*

Licensee personnel determined that the root cause for the second 'A' ESW pump failure was the assembly methods used in September 2003. Specifically, the use of a broach to remove a high spot in the pump coupling created a stress riser in the coupling. Therefore, the condition existed from September 1, 2003, when the pump was returned to service until the coupling failed on May 21, 2004. Once assembled and installed, the flaw could not be detected without disassembling the pump and performing a laboratory analysis of the coupling. However, engineering analyses performed on the coupling following the first failure identified the marginal design of the coupling. Specifically, when the licensee calculated imposed stresses in the coupling using finite element analysis, the analysis identified that the coupling would be subjected to significant yield stresses. While the model was simplified, licensee personnel failed to refine this analysis to sufficiently understand available design margin and critical coupling parameters. In addition, the root cause report identified problems with vendor quality and material hardness, that if expeditiously pursued, could have prevented the second coupling failure.

c. *Determine that the evaluation documents the plant specific risk consequences, (as applicable) and compliance concerns associated with the issue both individually and collectively*.

Both the NRC and licensee performed extensive reviews of the second 'A' ESW pump failure using probabilistic risk assessment (PRA) techniques to determine the risk consequences of the event. These evaluations ultimately determined that the second 'A' ESW pump failure was of very low safety significance (Green), predominantly due to the relatively short period of time the pump could not operate.

Compliance concerns associated with the pump failure were previously documented as NCV 05000440/2005002-12, “Failure to Implement TS 3.4.10,” and NCV 05000440/2004011-02, “Repetitive Failure of ESW Pump Coupling.”

Root Cause and Extent of Condition Evaluation

a. *Determine that the problem was evaluated using a systematic method to identify root causes and contributing causes.*

The team reviewed the root cause report associated with the second 'A' ESW pump failure. Licensee personnel developed a time line as well as an event and causal factor chart to aid in the determination of the root and contributing causes for the event. In addition, licensee personnel performed metallurgical and stress analyses of the coupling to better understand the failure mechanisms. The team concluded that the licensee used a systematic approach to identify the root causes and contributing causes of the failure.

b. *Determine that the root cause evaluation was conducted to a level of detail commensurate with the significance of the problem.*

The team reviewed the root cause report associated with the second 'A' ESW pump failure and concluded that the root cause evaluation was conducted to a level of detail commensurate with the significance of the problem. As part of their root cause analysis, the licensee identified that a lack of management focus to ensure ownership and accountability existed. In addition, the licensee added the second 'A' ESW pump failure to the scope of the root cause documented in CR 03-05995 which addressed the cumulative issues underlying the multiple White findings in the Mitigating System cornerstone. CR 03-05995 identified multiple significant issues underlying the White findings. The PII was intended to address these causes.

c. *Determine that the root cause evaluation included a consideration of prior occurrences of the problem and knowledge of prior operating experience.*

Both the September 1, 2003, and May 21, 2004, 'A' ESW pump failure root cause evaluations addressed prior occurrences of the problem and the knowledge of prior operating experience. The root cause of the second 'A' ESW pump failure discussed weaknesses in the licensee’s decision-making process with specific discussion of the failure to pursue coupling weaknesses indicated by finite element analysis and failures to obtain additional design data from the pump vendor. As part of the corrective actions for the second failure, the licensee obtained and developed design information for the pump coupling which was then used to modify the coupling design.

d. *Determine that the root cause evaluation addresses the extent of condition and the extent of cause of the problem.*

The root cause for the second 'A' ESW pump failure adequately addressed the technical aspects of the failure both in terms of extent of condition and extent of cause.

Licensee personnel evaluated other pumps for similar coupling design and/or material composition. Based on this review, the licensee concluded that the population of vulnerable pumps was limited to the three ESW pumps.

The root cause report identified repetitive examples of weaknesses in vendor quality and analysis of safety implications. Based on the failure to address these identified and long-standing performance deficiencies, the report identified the additional root cause of a lack of management focus to ensure ownership.

Corrective Actions

a. *Determine that appropriate corrective actions are specified for each root cause and contributing cause or that there is an evaluation that no actions are necessary.*

The team verified that corrective actions, including actions to address previously issued NCVs, were specified and implemented to address the repetitive ESW pump failures. These actions included design changes to the ESW pump coupling to prevent future pump failures as well as actions to address organizational issues. These actions were included as part of the PII effort to improve overall plant performance.

However, as detailed in Attachment 1 of this report, a finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," was identified when licensee personnel failed to correct a CAQ identified in IR 05000440/2004008 regarding an NCV for the failure to properly inspect the re-assembly of ESW pump couplings. (Attachment 1, Item 1.14)

b. *Determine that the corrective actions have been prioritized with consideration of the risk significance and regulatory compliance.*

The licensee took immediate action to correct the design deficiencies associated with the 'A' ESW pump failure, including replacement of the 'B' ESW pump. The schedule for corrective actions to address other causal factors appeared to be based on the complexity of the task and outage scheduling. For example, corrective actions to improve vendor quality were scheduled for completion before the end of 2004. In part, the licensee credited completion of the PII to address some of the causal factors. Since the implementation of the PII was a long-term effort, the associated corrective actions to fully address the causes were scheduled to be implemented accordingly. However, these issues were also cultural in nature and could not be immediately resolved.

The team concluded that the licensee adequately addressed the immediate technical root causes of the pump failure and through the PII had established a long-term plan to address organizational and other non-technical root causes.

c. *Determine that a schedule has been established for implementing and completing the corrective actions*.

The licensee established a schedule through their corrective action process and their PII process.

d. *Determine that quantitative or qualitative measures of success have been developed for determining the effectiveness of the corrective actions to prevent recurrence*.

The licensee developed an effectiveness review for each of the root causes. However, the following issues were identified:

- The effectiveness review for the root cause of a less than adequate design prescribed that in order for the corrective action to be considered effective, an ESW pump coupling failure due to intergranular stress-corrosion cracking

(IGSCC) must not occur. The team reviewed this effectiveness measure and determined that there was not a technically justifiable reason to limit the unacceptable failure mode to IGSCC cracking.

- The effectiveness review of the root cause of less than adequate vendor quality prescribed that in order for the corrective action to be considered effective, there must be no occurrences in which parts for critical components are unavailable or fail to satisfy procurement requirements and result in a plant event. The team reviewed this criteria and determined that the necessity for an actual plant event was inappropriate since these types of events may not occur for some time with the installation of a flawed part. Therefore, the corrective action could be judged satisfactory despite the installation of flawed parts. In addition, the unavailability of a part could not be reasonably viewed to have the potential to result in a plant event.

- The effectiveness review of the root cause of less than adequate analysis of safety implications prescribed that in order for the corrective action to be considered effective, there must be no occurrences where decisions related to significant issues have not been appropriately evaluated, documented, and re-assessed for lessons learned. The team reviewed this criteria and determined that the criteria inappropriately focused on the use of the process for decision-making rather than the acceptability of the outcome.

Independent Assessment of Extent of Condition and Extent of Cause

a. *Perform a focused inspection to independently assess the validity of the licensee's conclusions regarding the extent of condition and extent of cause of the issues.*

Following the second 'A' ESW pump failure, the team concluded that the licensee had bounded the extent of condition and extent of cause for the coupling failure issue.

2.3 Quality Assurance, External Audits, and Self-Assessments Review

a. Inspection Scope

The team reviewed selected audits and assessments performed by the line organizations, quality assurance (QA) group, and external sources, to determine whether the licensee had demonstrated the capability to identify performance issues before they resulted in actual events or undesired consequences. The team evaluated management support of the audit and assessment process through a review of the staffing of the QA organization, management response to audit and assessment findings, and the contributions of the QA organization to improvements in licensee performance.

b. Observations and Findings

The team concluded that although the audits and assessments performed by the QA group, line organizations, and external organizations, identified appropriate issues, actions to address these issues had little substantive impact on performance. In addition, information obtained through interviews indicated that there had been no formal audits or assessments to address human performance issues. Specific examples included the following:

- The root cause investigation for CR 03-02086, “Stop Work Order Issued to Address Radiological Deficiencies During RFO9," generated by the QA department acknowledged that similar conditions with staffing, and roles and responsibilities could exist elsewhere with management. However, no actions were implemented to determine whether other departments were affected.

- Quality Assurance identified a deficient condition related to MOV operability due to the use of “Never-Seez” as a lubricant and generated a mode change restraint. However, actions were not implemented to ensure the prompt remediation of all safety-related MOVs. While the initial schedule prescribed that all affected valves be cleaned and re-lubricated by the end of RFO10, a revised plan extended that schedule through RFO12.

- The team noted that individual organization self-assessments and binning reports, while providing a good collection of data and information, provided only minimal assessment. For example, an Operations department self-assessment identified an 8-quarter negative performance trend. However, previous and subsequent self-assessments made no mention of the negative trend or actively tracked the effectiveness of corrective actions.

- Four self-assessments of the MOV program, performed over the last 4 years, identified similar weaknesses or deficiencies, and appeared weak, narrowly focused, and not fully effective. Corrective actions were often classified as enhancements and corrective action completion schedules were frequently extended. For example, Self Assessment 320-PES-2001 identified 15 enhancements, which had 38 subsequent due date extensions. Also, the root cause evaluation for MOV stem lubrication concerns identified unspecified "programmatic issues," but deferred a programmatic review to a CR with a lower level classification than the original MOV issue.

- Two assessments of foreign material exclusion (FME) controls associated with fuel failures concluded that the FME program was as good as top industry performers. However, licensee personnel continued to identify FME fretting damage as the root cause for fuel failures, and had not identified the source of the FME.

2.4 <u>Work Authorization and Allocation of Resources Review</u>

a. <u>Inspection Scope</u>

The team reviewed the maintenance backlogs to determine whether the process for allocating resources provided for the appropriate consideration of safety and compliance. The team also determined whether appropriate consideration was given to the management of maintenance backlogs to prevent the need for multiple workarounds that could increase the likelihood of an initiating event or complicate accident mitigation.

b. Observations and Findings

The team concluded that resources applied to the CAP had not been previously sufficient to allow for the timely implementation of the program. The following examples were identified:

- The root cause analysis associated with CR 04-02598 which was generated because the 'A' ESW pump failed to produce required flow had six due date extensions, of approximately two months total. The reasons provided to justify the extensions were related to limited resources, unavailability of personnel, and fatigue due to working long hours.

- Four extensions were requested to address organizational issues associated with the HPCS pump start failure identified in CR 03-01369. The first two extensions were requested and granted because CARB had too many priority CRs (e.g. SCAQs) to review. The last two extensions were requested and granted due to a new investigator being assigned to complete the evaluation.

- Two CR extensions which caused a delay of 2 months were granted for the root cause evaluation associated with CR 03-04309 which was generated to address the issues behind the root cause, associated documentation, and violation of the CAP during the development, investigation, and reviews of a HPCS pump failure to start.

2.5 Review of Station Performance Goals and Strategic Plans

a. Inspection Scope

The team evaluated the licensee's performance goals to assess whether these goals and associated strategic plans were aligned with the actions needed to correct known performance issues. The team reviewed corporate, site, and organizational strategic plans, as well as other associated licensee documents.

b. Observations and Findings

Strategic plans were incorporated into the Perry PII which was developed to improve plant performance. The results of the team's review of the PII is discussed in Section 4 and Attachment 2 of this report.

2.6 Employee Concerns Program Review

a. Inspection Scope

The team performed a review of the licensee's Employee Concerns Program to determine whether licensee personnel were hesitant to raise safety concerns and whether safety significant concerns entered into the Employee Concerns Program received an appropriate level of attention. In particular, the team determined whether weaknesses in the Employee Concerns Program had contributed to previously identified performance deficiencies; whether additional safety issues existed that had not been adequately captured in the licensee's CAP; and whether weaknesses in the Employee Concerns Program had resulted in issues associated with the establishment of a safety conscious work environment (SCWE).

b. <u>Observations and Findings</u>

The team did not identify any weaknesses in the Employee Concerns Program that contributed to recent station performance deficiencies or adversely impacted the establishment of a SCWE. The nuclear safety concerns that had been identified through the Employee Concerns Program were appropriately addressed through the CAP.

Although the team concluded that the Employee Concerns Program was functioning properly and the licensee had established an environment where workers felt free to raise safety concerns, the team noted two potential challenges:

- The results of an independent SCWE evaluation and a licensee-administered SCWE survey of plant employees conducted in the later half of 2004 indicated a decline in positive SCWE responses compared to 2003 data.

- Several CRs or Employee Concerns Program concerns had been raised by plant employees in 2004 and January 2005 concerning a member of plant management whose style of interpersonal communication was interpreted by those employees as intimidating and possibly not conducive to the establishment of a strong SCWE.

At the end of this inspection, licensee personnel were in the process of identifying actions to address both challenges.

2.7 <u>Operating Experience Program Review</u>

a. <u>Inspection Scope</u>

The team conducted a review of the operating experience program to determine if appropriate actions were taken to address potential plant problems identified as a result of industry operating experience. The team reviewed the licensee's governing operating experience review procedure, program assessments, and the backlog of open items. Interviews were conducted with program personnel as well as line organizations. The team also reviewed selected 10 CFR Part 21 reports and NRC Information Notices and other generic correspondence to determine if the program had adequately assessed the issues for applicability at the site.

b. <u>Observations and Findings</u>

The team concluded that the use of industry information for previously documented performance issues had not effectively integrated industry information into plant programs. Specific examples included:

- During this inspection and as detailed in Attachment 1 of this inspection report, the team identified that licensee personnel continued to use “Never-Seez” in safety-related MOV applications although industry operating experience identified that “Never-Seez” was not an adequate MOV stem lubricant. As a result, over a 10 year period, licensee personnel deferred MOV stem lubricant replacement while multiple MOVs failed as-found test acceptance criteria and exhibited severe stem nut wear. (Attachment 1, Item 1.5)

- Hydramotor actuators, used in multiple safety systems, exhibited a higher than normal failure rate of 17 failures in 7 years. Licensee personnel did not effectively use operating experience that was available, including that available through the Nuclear Heating, Ventilation, and Air Conditioning (HVAC) Users Group, to identify failure mechanisms and improve performance.

- General Electric (GE) Service Information Letters (SILs) and other industry operating experience identified that GE contactors CR105, CR205, and CR305 used in the reactor protection system (RPS) had a limited service life. Licensee reviews were narrowly focused and had not considered the contactor use in non-RPS applications.

- Fuel failures, typically attributed to FME fretting damage, had occurred in 9 of the last 10 operating cycles. In response to previous fuel failures, licensee personnel had not effectively collected or evaluated operating experience with sufficient engineering rigor to identify effective corrective actions to prevent future fuel damage. The team noted that the licensee had developed a number of aggressive activities, to be implemented during RFO10 to address the issue.

3.0 Assessment of Performance in the Reactor Safety strategic performance area

3.1 <u>Background</u>

The team selected the RHR system and the Division 1 and Division 2 EDGs for detailed review. The selection was based on these systems’ importance to overall plant risk, and for the RHR system the fact that performance issues associated with this system had not been identified recently, and for the EDGs, the fact that a number of self-revealed performance issues had just very recently been identified. These selections provided the team the opportunity to review both the licensee's ability to identify issues as well as the licensee's ability to identify and implement corrective actions to address identified issues.

To satisfy the overall objectives of the IP 95003 inspection, the team used the guidance in IP 95003 and reviewed the following key attributes during this phase of the inspection:

- Design
- Human Performance
- Procedure Quality
- Equipment Performance
- Configuration Control
- Emergency Preparedness

3.2 Design

a. Inspection Scope

The team reviewed licensing and design basis documents (DBDs) for these systems, including the Updated Final Safety Analysis Report (UFSAR), calculations, engineering analyses, and system descriptions, to determine the functional requirements of the systems for normal, abnormal, and accident operating conditions. The team reviewed a sample of risk-significant plant modifications for the selected systems, including those that involved vendor supplied products and services to determine whether the design changes had an adverse impact on the ability of the systems to perform their design basis functions and determine whether the changes would result in an unexpected initiating event. During this review, the team evaluated the effectiveness of the licensee in controlling design and licensing information, in providing necessary calculations to support plant changes, and in developing and implementing thorough post-modification testing procedures. The team assessed the adequacy of the licensee in evaluating applicable system and support system design attributes and regulatory requirements. The team also reviewed system modifications to ensure that original design and accident analyses assumptions were not invalidated by the changes. Additionally, the team reviewed the modifications to confirm that the licensee had properly evaluated any required changes or additions to plant procedures.

The team conducted general walkdowns of the systems. Also, recent changes to plant maintenance and operating procedures were also reviewed to ensure that they did not result in inadvertent design changes to the systems. For procedures that involved design changes, the team ensured that the change was subjected to the appropriate design change processes, including a review in accordance with 10 CFR 50.59, "Changes, Tests, and Experiments."

The team also reviewed a sample of CRs to assess the effectiveness of corrective actions for deficiencies involving design activities.

b. Observations and Findings

b.1 Summary of Observations

Overall, the team concluded that the systems as designed and modified were operable and that the design and licensing basis of the systems were sufficiently understood. However, some findings and observations related to design modifications and engineering-related corrective actions to address performance deficiencies were identified. Notwithstanding the overall acceptability of performance in the engineering area, the team identified common characteristics in a number of problems identified during the inspection. These characteristics included, in some cases, a lack of technical rigor in the development of engineering products which resulted in an incorrect conclusion. Also, there appeared to be, at times, a lack of a questioning attitude to off-normal conditions. Finally, communications between engineering and other organizations such as operations and maintenance sometimes hindered the resolution of problems.

b.2 Observations and Findings Related to Design Control Issues

In the area of design, the team identified the following issues directly associated with design control deficiencies:

- During this inspection and as detailed in Attachment 1 of this report, licensee personnel failed to conduct adequate post-modification testing to verify the adequacy of a design change which modified the control circuit of a RHR system valve. (Attachment 1, Item 4.1)

- During this inspection and as detailed in Attachment 1 of this report, licensee personnel relied on the replacement of fuses for MOVs in the ESW and RHR systems for safe shutdown, which did not meet fire protection requirements. (Attachment 1, Item 4.2)

- During this inspection and as detailed in Attachment 1 of this report, licensee personnel failed to adequately evaluate the effect of water intrusion on the insulation composite installed in the EDG exhaust enclosure. (Attachment 1, Item 4.3)

Technical Rigor Weaknesses

The team observed numerous instances of weak technical rigor in engineering products. Some examples included the following:

- During this inspection and as detailed in Attachment 1 of this report, licensee personnel failed to adequately evaluate the effect of water intrusion on the insulation composite installed in the EDG exhaust enclosure. Specifically, licensee personnel implemented Engineering Change Package (ECP) 05-0032 to insulate the EDG safety-related exhaust missile barrier. The purpose of this insulation modification was to ensure that the concrete of the exhaust missile barrier did not exceed a temperature of 150°F during normal operations and 350°F during accident conditions. Portions of this insulated enclosure were known to be exposed to various weather conditions, such as rain and snow, through four screened openings. The insulation vendor supplied documentation to the licensee which stated that water could affect the thermal quality of the insulation and provided a method to determine if there was any degradation of the insulation. Given this information, the licensee failed to include any analysis of the potential effects of water intrusion in the modification package or in any of the associated calculations. (Attachment 1, Item 4.3)

  Also, during a walkdown of the completed modification, the team identified that holes where threaded rod passed through stainless steel plating and into the insulation were not completely covered, directly exposing portions of the insulation to the environment. Based upon discussions with the project manager, the team discovered that these areas were designed to be covered with flashing, and that the insulation was not intended to be directly exposed to the outside environment. As a result, licensee personnel installed flashing, as appropriate, to preclude the direct exposure of the insulation to the environment.

- During this inspection and as detailed in Attachment 1 of this report, the team identified several instances of weak technical rigor in the area of SLC-ATWS design. These weaknesses included an incomplete understanding of the ATWS analysis, an incomplete understanding of relief valve setpoint methodology, and the failure to identify appropriate relief valve blowdown assumptions. (Attachment 1, Item 1.1)

- The team reviewed ECP 03-0245A which increased the size of the motor actuator and adjusted the gear ratio for safety-related MOV 1E12F0028B to provide additional torque capability to ensure successful operation of the MOV during a design basis event. Licensee personnel completed this modification and performed post-modification testing on March 5, 2005. As documented on Attachment 5 of FTI-F0016, "MOV Field Data Sheet," the as-left setting for rotor number one was 1-1/4 stem nut turns from the backseat. The specification listed on this data sheet for the rotor number one setting was greater than or equal to ½ stem nut turns, but less than or equal to one stem nut turn. Although the setting was out of this required range, engineering personnel considered the as-left value of 1-1/4 stem nut turns to be satisfactory without any justification in the available documentation. The team questioned whether adequate justification existed for the as-left setting. Licensee personnel generated CR 05-03994 which acknowledged this deficiency and subsequently provided an adequate justification for the as-left setting.

- The team reviewed an operability determination (OD) associated with CR 05-03366 which evaluated the effect of EDG oscillations on ESW pump motors. The evaluation focused on frequency, and determined that a 24 percent margin remained. Following questions from the team, the condition was further evaluated taking motor currents into account, as required, and although the margin was reduced, it remained acceptable.

- The team reviewed the design changes associated with Fuse Size Change Requests 96-004 (P45-F068A), 96-005 (P45-F130A), and 96-008 (E51-F022), including selected portions of Calculation FSPC-0018, Revision 6. The team identified that the calculations had several critical assumptions, but had not established an adequate basis for the assumptions, or verified adequate margin to a design limit (e.g., motor safe stall time). Calculation weaknesses included:

    - The safe stall time utilized was a "typical" value used in industry publications. No specific Limitorque or Reliance Motor data had been utilized, nor had the vendors been requested to provide a safe stall time.

    - Institute of Electrical and Electronics Engineers (IEEE) Standard 1290-1996, "MOV Motor Application, Protection, and Control in Nuclear Power Plants," was referenced as a basis for fuse size methodology. IEEE 1290 provided a method to calculate a safe stall time, based on specific motor performance curves. However, no specific calculations were performed.

- Although the calculation assumed a constant locked rotor current, Limitorque Technical Update Bulletin 93-03, "Starting Torque at Elevated Temperatures," stated locked rotor current would decrease as motor temperature increased.

- Fuse melting curves, instead of fuse clearing curves, were used.

The team concluded that licensee's calculations were not conservative because the use of fuse melting curves, in conjunction with an assumption that the locked rotor current was constant, would result in a predicted fuse clearing time sooner than actual. Licensee personnel reviewed the margins associated with the fuse sizing calculations and initially determined that although the motor stall current might last longer than predicted, the motors were still adequately protected, except for RHR E12-F027A. Licensee personnel indicated that for E12-F027A, the fuse sizing may not be adequate to ensure motor protection from fire-induced spurious operation, because a revised fuse clearing time prediction exceeded the nominal value assumed for motor safe stall time.

The team determined this was a minor issue because the only valve adversely affected by the calculation weaknesses was not required to be able to achieve or maintain hot shutdown (i.e., only a cold shutdown item). The licensee entered this issue into their CAP as CR 05-04462.

- One of two RCIC condensate return valves to the condensate storage tank (CST), E51-F022, was designated as a hot shutdown active component, could be controlled from the RSP, and was subject to fire damage. The second condensate return valve to the CST, E51-F059, was in series with E51-F022, and was protected from fire damage. For E51-F022, licensee personnel substituted manual actions to replace fuses, in lieu of maintaining the circuits free from fire damage. The team identified that there were no procedure instructions to diagnose, identify, or replace the fuses, and no fuses were pre-staged in the RSP room. The licensee's safe shutdown procedures did not require the operation of this valve, or take credit for valve position. Licensee personnel stated that the valve was mis-characterized in the Safe Shutdown Capability Report (SSCR), and should have been designated as a "spurious operation" component, because a second in-series valve would prevent flow divergency. The team determined this was a minor issue because the valve's position did not affect the ability to achieve or maintain safe shutdown.

  An RHR injection isolation valve (E12-F027A), was designated as a hot shutdown active component, could be controlled from the RSP, and was subject to fire damage. There were no procedure instructions to replace the fuses and no fuses were pre-staged. License personnel stated that the valve was mis-characterized in the SSCR, and should have been designated as a "cold shutdown" active component, because the valve was needed to achieve cold shutdown, not maintain hot shutdown. The team concluded this valve was needed to transition from RCIC operation to RHR shutdown cooling and, as such, was not necessary for hot shutdown. For a cold shutdown component, fire damage repairs must be accomplished within 72 hours. In addition, Branch

Technical Position 9.5-1, Section C.5.c, "Alternate or Dedicated Shutdown," required that materials for cold shutdown repairs shall be readily available onsite and procedures shall be in effect to implement repairs. The team determined this was a minor issue because it was reasonable to assume that repair actions could be accomplished within a 72 hour period.

As an immediate corrective action, for these two issues, licensee personnel revised Integrated Operating Instruction (IOI)-011, "Shutdown from Outside the Control Room," to include instructions to diagnose spurious valve actuations, and replace fuses as appropriate. In addition, licensee personnel pre-staged fuses in the RSP room for these valves.

- The team identified a potential vulnerability regarding the root cause evaluation for the August 14, 2003, LPCS/RHR 'A' waterleg pump air-binding event, in that engineers used piping isometrics to evaluate and assess potential air accumulation locations, without performing actual piping field walkdowns. The team determined that this method may not be fully effective to ensure that no excessive piping slopes (reverse slopes) exist where air accumulation may occur and remain undetected.

b.3 <u>Observations and Findings Related to Lack of Sensitivity to Off-Normal Conditions</u>

During the inspection, the team identified that, at times, engineering personnel demonstrated a lack of sensitivity to off-normal conditions as evidence by the following:

- During this inspection and as detailed in Attachment 1 of this report, licensee personnel failed to adequately address concerns regarding SLC system relief valve testing failures. In each case, a CR was initiated, but the affect on system performance for repetitive relief valve lift testing results outside of the setpoint tolerance was not fully assessed. Licensee personnel failed to recognize the significance of the test failures. When the historical relief valve failures were assessed, the licensee concluded that on two prior occasions, the as-found condition of a SLC relief valve would have prevented the system from performing its design function. Licensee personnel also determined that the test failures were not currently reportable, because the time of discovery was greater than 3 years after the time of occurrence which was consistent with the guidance in NUREG-1022, Revision 2, "Event Reporting Guidelines - 10 CFR 50.72 and 50.73," The licensee entered these issues into their CAP as CRs 05-3686 and 05-3827. (Attachment 1, Item 1.1)

- During this inspection and as detailed in Attachment 1 of this report, the team identified that licensee personnel failed to implement adequate corrective actions in a timely manner to address the inappropriate use of "Never-Seez" lubricant in safety-related MOV applications. In the early 1990s, multiple industry sources identified that Never-Seez was an inadequate MOV lubricant, because it increased friction and wear. The licensee deferred lubricant replacement for over a 10 year period. During that period, there were multiple valve test failures

- during scheduled as-found performance testing. Engineering had established a practice of re-calculating a revised acceptance value, rather than issue a CR to understand the root cause of the issue. (Attachment 1, Item 1.5)

- An EDG trip on reverse power during an August 2003 LOOP event was not investigated until after the EDG failed during a subsequent surveillance test. Following the LOOP event, an EDG reverse power trip was inappropriately considered by cognizant engineering personnel to be an expected occurrence. In addition, during the post scram review for the event, engineering personnel failed to identify an abnormally high 4 kilovolt (KV) bus voltage (greater than 4400 V). The issue was not identified until after the EDG failed the subsequent surveillance test.

- Given the prior licensee history with air-binding of the LPCS/RHR 'A' waterleg pump, the team determined that the licensee had not yet implemented a program to manage or monitor gas and/or air generation. Specifically, the team noted that routine venting procedures such as Surveillance Instruction (SVI)-E12-T1182 did not provide acceptance criteria for measuring and monitoring or trending the amount of air vented. In addition, the team identified that operators used a solid hose for venting, vice a clear hose; and some operators may have improperly assumed that the air observed during venting was not from the emergency core cooling system (ECCS) piping, but was air that was being cleared from the hose.

  SVI-E12-T182 required the generation of a CR to evaluate past operability and surveillance frequency, if excessive air was vented. However, the team identified that there was no clear acceptance criteria provided to the operators which defined “excessive” air. Further, the team verified that no CR had ever been generated to report any amount of air in piping during performance of this procedure. Engineering personnel had determined that gas generation was possible due to the waterleg pump stripping gasses from solution. In addition, continued industry events demonstrated that gas could accumulate in ECCS systems, despite ongoing prevention efforts. Therefore, gas accumulation warranted proper management to provide reasonable assurance that the ECCS systems would properly function. CR 05-03135 was generated to identify these concerns. In addition, corrective actions associated with CR 04-06472 required a comparison of the current Perry piping venting philosophies with industry practices. This action was scheduled to be completed by July 2005.

b.4 Observations and Findings Related to Engineering Communications

Compounding corrective action implementation problems, the team observed that communications between engineering and other organizations sometimes hindered effective problem resolution. Some examples included:

- Electrical engineering provided informal guidance to operations regarding bus operability that appeared to conflict with the electrical DBDs. Engineering personnel informed Operations that short bus voltage excursion above 4400 Volts Alternating Current (VAC) was not an operability concern. During interviews, the team identified that the design limit of the 4 kV power distribution system was 4400 VAC, and therefore any increase above that design limit warranted an engineering evaluation to assess the effects on the connected loads.

- The team identified that to address CR 03-4912 regarding an EDG reverse power trip, engineering personnel conducted an informal review of a 4 kV bus over-voltage condition to assess the impact on the individual bus loads. The review was summarized in an e-mail to operations, but was not documented in an associated CR, and not was retained in QA Records.

b.5 (Closed) Unresolved Item 05000440/2005002-11: Effect of EDG Operation with Open TRDs on Enclosed Tornado/Missile Enclosure

As discussed in IR 05000440/2005002, due to repetitive problems with testable rupture disc (TRD) performance, licensee personnel completed a 10 CFR 50.59 screening on January 9, 2005, to place the TRDs in an unlatched position during normal EDG standby conditions. The screening concluded that a 10 CFR 50.59 evaluation was not required. The Division 2 EDG TRD was unlatched on January 7, 2005, and the Division 1 EDG TRD was unlatched on January 8, 2005. On January 12, 2005, the 10 CFR 50.59 screening was revised to include the Division 3 EDG TRD.

On January 18, 2005, licensee personnel identified that contrary to statements in the 10 CFR 50.59 screening, the temperature in the EDG TRD tornado missile enclosure could exceed the limiting temperature for the enclosure concrete. As a result, on January 19, 2005, the licensee declared all three divisional EDGs inoperable (NRC Event Notification System (ENS) Report 41344). The EDG TRDs were relatched and temporary modifications for debris shields and heat shields were installed. The three EDGs were subsequently declared operable on January 30, 2005.

The licensee subsequently completed an analysis of the capabilities of the tornado missile enclosure and concluded that the concrete enclosure, as originally designed, supported operability of the EDGs. On March 23, 2005, the licensee retracted ENS Report 41344.

Unresolved Item (URI) 05000440/2005002-11 was opened, pending a review of the licensee’s past operability analysis of this issue.

During this inspection, the team reviewed OD 05-00463, Revision 1, which addressed the issue. This review included evaluation of MPR-2784, Revision 1, "Perry Nuclear Plant EDG Exhaust Temperature Concerns - Past Operability Evaluation," which addressed the operability issues documented in OD 05-00463.

Based on examination of these documents, as well as an interview with the responsible engineer and reviews of other information, such as previous turbocharger inspections, the team determined that the licensee’s review of past operability for this condition was adequate. Unresolved Item 05000440/2005002-11 is closed.

3.3 Human Performance

By nature of the design of nuclear power plants and the role of plant personnel in maintenance, testing, and operation; human performance plays an important role in normal, off-normal, and emergency operations. Human performance impacts each of the Reactor Safety strategic performance area cornerstones and therefore was considered across the entire inspection.

To satisfy the overall objectives of the IP 95003 inspection, the team used the guidance in IP 95003 and considered the following human performance areas for review:

- Effectiveness of Corrective Actions for Deficiencies Involving Human Performance
- Organizational Practices
- Training and Qualifications
- Communications
- Control of Overtime and Fatigue
- Human-System Interfaces

3.3.1 Assessments and Corrective Actions for Human Performance and Organizational Issues

a. Inspection Scope

The team evaluated the licensee's CAP and its implementation, focusing on the licensee's ability to identify, assess, and effectively correct performance deficiencies associated with human and organizational performance.

b. Observations and Findings

The team concluded that the licensee's tools for assessing human and organizational performance had not been effectively used. Specifically, human and organizational performance issues were rarely assigned a significance level above a CAQ, and in those cases where organizational performance may be part of a significant issue, the organizational portion was typically addressed by a separate CR assigned a lower significance level. For example, the organizational performance issues associated with the SCAQ CRs for the December 2004 and January 2005 reactor recirculation pump downshift events were not included in the SCAQ assessment, but evaluated in a CR designated only as a CAQ.

By relegating the organizational issues to a CR classified as a CAQ, all of the process-required conditions associated with a SCAQ were not applicable. For example, the SCAQ requirement that corrective actions must address recurrence, that an effectiveness review has to be performed, and that an extent of cause and extent of condition has to be addressed, were not required for CAQs.

The team reviewed the licensee's 2004 CR database. The review identified that human and organization performance cause codes accounted for the top 14 areas where problems existed. However, although 4000 CRs were generated in these 14 areas, none of the personnel or human performance CRs individually or collectively were judged to be significant enough to warrant a SCAQ level evaluation.

The team noted that although corrective actions for most human performance deficiencies consisted of remediation training, personnel counseling, or procedure revisions, no assessments were conducted which confirmed that these actions were appropriate or had been effective.

The following specific issues were identified:

- CR 03-05065 associated with an 'A' ESW pump failure, failed to address significant organizational performance issues. Although the CR assessment had been approved by the CARB, the revision to the original CR failed to address why the CR had not identified the performance issue or why CARB had approved it.

- CR 04-06472 associated with venting of safety-related systems identified that previous corrective actions had not been effective. However, a review was not conducted to identify the causes for the organizational issues associated with the implementation of the inadequate corrective actions.

- CR 05-00094 associated with a second reactor recirculation pump down shift event, identified as a contributing cause a “lack of organizational commitment to the program implementation of NOP-ER-3001, ‘Problem Solving and Decision Making Process’.” However no corrective actions to understand and address this issue were implemented.

- CR 03-06213 associated with the mis-alignment of the ESW system and that resulted in the licensee declaring the ESW system, all EDGs, and all ECCS systems inoperable identified a heavy workload, resources, and work planning as contributing causes. The team reviewed the licensee’s corrective actions and identified that none of these issues was specifically addressed. Further, actions were not developed to address why non-licensed operators (NLOs) continued to perform the procedure after receiving information that the steps implemented were not consistent with those performed during previous evolutions. Further, no assessment or follow up actions were generated to address why the Operations Foreman instructed plant operators to line up the ESW system using the incorrect procedure section.

- CR 03-04280 documented that while performing a LPCS system surveillance, a control room operator started a LPCS pump using an incorrect procedure section. The apparent causes for the event were identified to be a failure to follow procedures, failure to prepare for the work, and ineffective management work review. Although the CR identified that the operator was distracted from the task at hand, no follow-up reviews or corrective actions were identified to address possible causes for the distractions.

- CR 04-01688 was generated to address organizational effectiveness issues. The root cause report discussed use of training and performance tools being set aside due to no perceived value in their use; perceived schedule pressures, even for routine work; and the lack of penalties for disregarding human performance tools. The report also stated that there was "surpassing evidence that schedule adherence is more valued than human performance tools." The team reviewed the licensee's corrective actions and identified that the corrective actions failed to address the issues of schedule pressure and schedule adherence.

The licensee recognized the human performance weaknesses that existed and documented the issue in CR 05-02517. The following actions were planned or in progress to address human performance at the conclusion of this inspection:

- A root cause investigation to specifically address human performance was scheduled to be completed by June 10, 2005, with identified corrective actions to be incorporated into the Perry PII.

- The Organizational Effectiveness area of the PII included human performance as a key success area for the RFO10 "Report Card".

- The Training Effective area of the PII included human performance tools training for management and staff with plans to incorporate additional human performance training into the continuing training program.

- Additional effectiveness reviews and assessments were scheduled after the training.

Management oversight and peer checking reviews commenced in late April 2005. During the RFO10 refueling outage, several "Stop Work" actions were implemented by the QA group and licensee management in response to human performance errors which indicated that corrective actions to address human performance problems had not been completely effective.

3.3.2 Organizational Practices

a. Inspection Scope

The team conducted in excess of 50 hours of control room observations, including a 24-hour continuous coverage period during a reactor startup following RFO10. Operators were observed performing evolutions, tests, and responding to annunciators. The team also accompanied operators during the performance of operator rounds. Written logs and shift status reports or updates were reviewed for completeness and accuracy to ensure they provided sufficient detail.

Additionally, the team observed scheduled and non-scheduled maintenance activities, the control room command function, and implementation of compensatory measures as required by risk and safety evaluations. The team observed pre-job briefings, evaluated communication between operations and other departments, and interviewed operators to determine their awareness and understanding of ongoing activities.

Activities of field support supervisors and plant operators were observed to determine whether operations personnel were knowledgeable about the status of systems, structures, and components; equipment performance; and the impact of ongoing work activities.

b. <u>Observations and Findings</u>

During the inspection, a number of self-revealing findings related to procedure adherence occurred which had a strong human performance contribution. These events have resulted in an unplanned engineered safety feature actuation, a loss of shutdown cooling, an unplanned partial drain down of the suppression pool, inadvertent operation of a control rod (a reactivity event), and various configuration control errors.

The team reviewed the events which occurred during the inspection and identified that the procedure adherence problems had a number of common characteristics. In a number of cases, personnel failed to properly focus on the task at hand. Although prior to many events, pre-job briefings were held and procedures were adequate to accomplish the intended activity, personnel failed to sufficiently focus on the individual procedure step being accomplished and performed an action outside of that prescribed by the procedure. In some cases, the team determined that a lack of a questioning attitude contributed to the procedure problems which occurred. Although information was available to personnel which could have, if fully considered, prevented the procedure adherence issues that occurred, that information was not sought out or was not questioned. Finally, in some cases, inadequate supervisory oversight directly resulted in the findings identified during the inspection. The presence of supervisors with the necessary standards to foster good procedure adherence could have acted as a significant barrier to prevent some of the problems which occurred. The team concluded that human performance continued to be a substantive cross-cutting issue.

During this inspection, the team identified numerous examples of procedure adherence issues with a strong human performance error contribution. The following procedure adherence issues, listed chronologically, were identified in previous NRC inspection reports or during this inspection:

- As discussed in IR 05000440/2005002, Intermediate Range Monitor (IRM) 'A' was discovered to be inoperable during a reactor startup on January 30, 2005, when maintenance personnel failed to properly install a cable between the IRM detector and IRM instrument.

- As discussed in IR 05000440/2005002, on February 3, 2005, while calibrating containment/drywell purge exhaust radiation monitor 1D17-K660, an Instrumentation and Controls (I&C) technician inadvertently pressed an incorrect trip test push button resulted in an engineered safety feature (ESF) actuation.

- During this inspection, on February 22, 2005, while conducting a plant cool down in accordance with IOI-7, "Cooldown Following a Reactor Scram with Main Condenser Available," the operators established a level band of 240-260 inches contrary to the IOI-specified band of 247-257 inches. By procedure, the shift manager (SM) may "NA" a step within an IOI and provide an explanation for the

"NA." In this instance, the operator initialed the step, indicating it had been completed despite selecting a different level band. The licensee determined that the operator had selected the band based upon the plant schedule vice the IOI. Since the band selected was technically acceptable, the procedural deviation was minor in nature. However, the procedure was annotated as if a step had been completed when it had not with no documented explanation for why a band contrary to the procedure had been selected, and the operator used a schedule instead of a reviewed and approved procedure to establish critical plant parameters.

- During this inspection and as detailed in Attachment 1 of this report, on February 26, 2005, licensee personnel identified that an operator signed off step 7 and step 8 of SVI-E51-T1298 which verified RCIC disconnects shut although the disconnects were open. (Attachment 1, Item 3.2)

- As discussed in IR 05000440/2005002, on February 27, 2005, during a local leak rate test, RHR 'A' suppression pool suction valve 1E12-F004A was opened with the 'A' RHR system drained. As a result, the suppression pool drained through an open drain valve to the auxiliary building equipment drain sump. The draining was terminated when the suction valve was closed, but only after about 8500 gallons had been unintentionally drained from the suppression pool.

- As discussed in IR 05000440/2005002, on February 28, 2005, while removing a jet pump plug assembly from the reactor vessel, due to a human performance error, the plug broke loose from the handling pole, landing on several fuel bundles on the reactor core.

- During this inspection, on March 1, 2005, during the performance of Work Order (WO) 200073510, which specified the removal of RCIC exhaust vacuum breaker check valve 1E51F0079, an adjoining RCIC check valve, 1E51F0081, was removed instead.

- During this inspection, on March 2, 2005, during the performance of WO 200094531 which specified the removal and replacement of RHR system orifice plate 1E12D0001C, the wrong RHR system orifice plate was removed and replaced.

- As discussed in IR 05000440/2005002, on March 10, 2005, during RFO10 refueling activities, the control room senior reactor operator inadvertently withdrew control rod 58-35 one notch from position 00 to position 02 while attempting to verify the position of all rods in the core.

- During this inspection and as detailed in Attachment 1 of this report, on March 16, 2005, licensee personnel performing jumper removal activities performed the incorrect system restoration section of a procedure. As a result, a jumper was left installed in an electrical cabinet that was only identified when the jumper could not be located the next day to conduct an unrelated task. The jumper affected the operation of the drywell purge system isolation damper. (Attachment 1, Item 3.2)

- On March 16, 2005, during the performance of SVI-E12-T2210, it was discovered by local leak rate testing (LLRT) technicians that RHR valves E12-F058A and E12-F059A were not appropriately tagged or positioned as expected. Upon further investigation, it was discovered that the opposite train valves were incorrectly tagged with LLRT tags. This event was minor since both RHR trains were secured and drained.

On March 17, 2005, during RFO10, a “Stop Work” action was implemented by senior licensee management for all operations activities not associated with normal and/or emergency plant operations as a result of the more recent procedure adherence issues with a human performance element identified above and which occurred over a relatively short period of time.

On March 18, 2005, following the implementation of corrective actions to address the human performance concerns, the “Stop Work” action was lifted and refueling outage activities resumed.

Subsequently, the following additional procedure adherence issues occurred:

- During this inspection and as detailed in Section 7 of this report, on March 21, 2005, maintenance technicians re-assembling the 'A' ESW pump failed to follow the procedural instructions specified in General Maintenance Instruction (GMI)-039, “Disassembly/Reassembly of the Division 1 and 2 Emergency Service Water Pumps,” which required the pump shaft set screws to be lubricated and torqued to a required value by following a specified sequence. A Quality Assurance auditor noted that the maintenance technician, who was being observed by his maintenance supervisor, was not lubricating the set screws and was not torquing the set screws using the specified sequence contained in the procedure.

- On March 20, 2005, clearance tags intended to be hung in panel 2R61 for sliding links SL E1-D98 and SL E1-D99 were inadvertently hung on the sliding links in panel 1R61; a wrong unit error.

- As discussed in IR 05000440/2005006, on April 5, 2005, operators failed to perform procedure steps in the order as written and inadvertently isolated the nuclear closed cooling (NCC) system, resulting in a loss of shutdown cooling event.

Subsequently, on April 6, 2005, a second “Stop Work” action was issued by the licensee’s Nuclear Oversight organization to the Operations department. The stop work directive was a result of the following concerns:

- Previous Operations stand-downs had been ineffective to arrest poor performance;

- A loss of shutdown cooling occurred due to a procedure adherence and human performance error while performing system lineups to support LOOP testing; and

- De-certified licensed operators performing control room manipulations.

As detailed in CR 05-03089, the basis for the action was the failure of licensee personnel to comply with written procedures or instructions and the failure of previous remedial actions to adequately address Operations department human performance errors.

On April 8, 2005, following the implementation of corrective actions to address Nuclear Oversight's concerns, the "Stop Work" action was lifted and refueling outage activities resumed. Corrective actions included the reinforcement of management expectations for all supervisors, superintendents, and managers at an "all-hands" meeting that it was mandatory that all personnel at the facility strictly comply with procedural requirements at all times as specified in NOP-LP-2601, "Procedure Use And Adherence," and PAP-0528, "Procedure Use And Adherence Supplemental Items."

Subsequently, the following additional procedure adherence issues occurred:

- On April 19, 2005, the team observed a reactor operator provide procedural guidance to a field operator to isolate 'A' fuel pool cooling and cleanup (FPCC) heat exchanger in accordance with System Operating Instruction (SOI)-G41, Section 7.21. The team observed the reactor operator correctly direct the field operator to perform steps 1 and 2 to isolate the 'A' FPCC heat exchanger. However, in addition to steps 1 and 2, the field operator incorrectly performed step 5 of the procedure which opened the ECCW header vent valve. Unexpected water issued from the heat exchanger due to a short venting of the NCC side of the in-service heat exchanger. The field operator communicated the unexpected water and was directed to immediately re-close the vent valve. This issue was an example of a failure to follow field use procedure steps in order; however, it was minor because the system was out of service, the plant was shut down in Mode 4, and shutdown cooling was supplied by the RHR system.

- As discussed in IR 05000440/2005006, on April 21, 2005, during the performance of SVI-E22-T5397, electrical maintenance personnel intended to perform a step which placed a jumper in breaker cabinet 1303, but inadvertently placed the jumper in adjacent breaker cabinet 1302.

3.3.3 <u>Training and Qualifications</u>

a. <u>Inspection Scope</u>

The team determined whether the training and qualifications of station personnel was commensurate with the level of work assigned. The team conducted observations of training using the guidance and checklists found in NUREG-1220, Revision 1, "Training Review Criteria and Procedures." The team conducted interviews of trainees, supervisors, and instructors using the guidance in Inspection Procedure 41500, "Training and Qualification Effectiveness." Personnel were interviewed to determine their awareness and understanding of procedure changes, and whether they had received adequate training for their use.

b. Observations and Findings

The team observed one crew of licensed operators during Just-In-Time (JIT) training to prepare for plant restart and compared the training to the applicable IP 41500 checklists for simulator and classroom training. The training focused primarily on a scenario that incorporated the IOIs for plant startup from cold shutdown through full power operation. The instructors prepared and followed formalized operator training lesson plans based on objectives and goals. The lesson plans identified critical operations with stopping points. The instructors facilitated discussions before and after the critical operations that included "what to look for," previous Perry events, and Operating Experience (OE). Individual operators were responsible for identifying pertinent OE discussion material with the instructors providing oversight as well as instructing from prepared material. The scenario incorporated plans to test the digital feedwater control system, SOIs, and potential Off-Normal Instructions (ONIs) and Alarm Response Instructions (ARIs). Human performance tools were reinforced and practiced. The tools included communications, peer- and self-checking, and pre-job briefings. Emphasis was also placed on procedure use and adherence.

The licensee incorporated the use of a prepared script based on bench-marking at another plant that exhibited successful startups. The purpose of the script was to provide a guideline for expected operations. The script identified plant and system evolutions, referenced applicable procedures, critical operations, probable hold and delay points in the startup, and appropriate briefing points.

The team verified that the observed licensed operators in training were medically qualified and up to date in their licensed operator continuing training qualifications.

The team concluded that to the extent possible, the licensee’s JIT training for startup met the requirements contained in NUREG-1220, Revision 1, "Training Review Criteria and Procedures," and Inspection Procedure 41500, "Training and Qualification Effectiveness."

No findings of significance were identified.

3.3.4 Communications

a. Inspection Scope

The team assessed the quality of communications by observing whether communications were consistent with the licensee’s procedures during the conduct of operations, maintenance, and testing activities; whether instructions or information disseminated using the plant phone and paging system were clearly and concisely communicated; and whether personnel informed the appropriate level of management for any abnormal conditions or significant changes in plant equipment and systems.

The team reviewed a sample of written logs and shift status reports and updates to determine whether they provided sufficient detail to allow a full understanding of operationally significant matters, including abnormal occurrences or testing results and any compensatory measures taken; and describe changes in plant or equipment status in sufficient detail.

The team also evaluated the communications between various site departments and licensee management to determine whether these communications provided for continued safe plant operation. This was accomplished through an evaluation of the responsiveness and timeliness to requests for assistance and requests for problem resolution, and an evaluation as to whether other departments were aware of the extent and significance of deficiencies that had cross-cutting aspects which could impact other departments and organizations.

b. <u>Observations and Findings</u>

The team observed licensed operator communications with respect to the use of “three-part” communications with paraphrased repeat backs, use of the phonetic alphabet, and use of system descriptions vice acronyms. The team observed that directions were generally clear, concise, and free from ambiguity. The team also observed that craft personnel and engineers generally did not demonstrate the same quality of communications with their peers, but when interfacing with licensed operators in the control room; NLOs, craft personnel, and engineers were frequently corrected by licensed operators, and prompted to use repeat backs, phonetic alphabet, proper equipment terminology, and clear and specific terminology. The team concluded that licensed operator communications satisfactorily met the expectations and standards contained in Section 4.6, "Communication," of NOP-OP-1002, "Conduct of Operations." However, craft and NLO communications, although generally understood, did not consistently meet these expectations.

The team reviewed the control room reactor operator narrative log and shift turnover sheets. The team concluded they adequately discussed issues, and reflected equipment and plant status changes to allow understanding of operationally significant matters with respect to abnormal occurrences or testing results, and any implemented compensatory measures. The team concluded the reactor operator narrative log and shift turnover sheets satisfactorily met the expectations and standards contained in NOP-OP-1002, Section 4.13, "Log Keeping and Record."

The team observed several morning and afternoon control room shift turnovers to determine whether these turnovers conformed to the expectations and standards contained in NOP-OP-1002, Section 4.17, "Shift Relief and Turnover." The oncoming shift relieved the off going shift on station after performing an individual detailed walkdown of the control room panels with a face-to-face exchange of pertinent plant status information. Appropriate detailed information exchange and reviews of logs and turnover items were performed.

The team did not identify specific instances in which the appropriate level of management was not informed of abnormal conditions or significant changes in plant equipment and systems. However, the team did observe instances of weak communications between departments. The following specific examples were identified:

- Weak Communication During Turnover of EDG Operability Status

  The team questioned the control room operations crew to verify knowledge and awareness of plant status and operability issues. In one instance, the at-the-controls reactor operator was not aware of Division 1 EDG operability status. Licensee personnel had declared the Division 1 EDG inoperable following the discovery of insulation work contrary to the ARC procedure requirements. When questioned, the operator stated that the Division 1 EDG was operable. The operator was asked about the ARC issue and the operator stated that he was still reading about it, but believed the Division 1 EDG was operable. The team asked the senior reactor operator (SRO) about the status of Division 1 EDG. The SRO responded it was inoperable and provided the correct explanation.

- Weak Communications Between Control Room And Refuel Floor For Dryer Lift

  Although the RFO10 outage schedule identified a concurrent lift of the dryer with cavity flood-up, control room personnel expected a communication prior to the evolution. The refuel floor supervisor commenced the dryer lift without specifically informing control room personnel. As a result, an unexpected reactor vessel level decrease was identified by control room operators. Although the cause of the reactor water level change was understood by control room operators in a relatively short period of time, the lack of adequate understanding during the pre-job briefing and timely communication of the dryer lift to control room personnel by the refuel floor supervisor resulted in an unexpected decrease in reactor vessel level.

- Weak Communications During RHR Heat Exchanger Inspection

  The licensee identified a lack of communication and awareness of plant conditions. Control room personnel were aware of maintenance being performed on the 'A' RHR heat exchanger which required draining the heat exchanger and removal of the heat exchanger lower end bell for inspection. After the heat exchanger had been drained, maintenance personnel identified that an unexpected and significant amount of water issued from the heat exchanger when the end bell was removed. However, maintenance failed to report the event to the control room. As a result, the control room unexpectedly received RHR 'A' sump high level alarm 1H13-P601-18-D1. Based on meeting entry conditions for the unexpected and unexplained alarm, Operations entered Perry Emergency Instruction N11, dispatched an operator to the area, and performed Alarm Response Instruction actions.

The team concluded that communications between departments were not always well established and a lack of plant status awareness sometimes existed.

3.3.5 Control of Overtime and Fatigue

Because problems had not been previously identified, this area was not specifically reviewed during the inspection.

3.3.6 Human-System Interfaces

a. Inspection Scope

The team conducted an evaluation of human-system interfaces, including work area design and environmental conditions. In particular, during the observations of activities in the main control room and other areas in the plant, the team walked down control panels and evaluated the size, shape, location, function, and content of displays, controls, and alarms. The team also assessed whether panels and equipment were correctly labeled; evaluated work areas for accessibility of equipment, equipment layout, and emergency equipment locations; and evaluated the potential impact of environmental conditions on human performance.

b. Observations and Findings

Overall, the team concluded that human-system interfaces were adequate. However, the team identified the following examples in which the layout of equipment or the environment could present a challenge to operators:

- The team identified that the EDG rooms were very noisy during testing which inhibited face-to-face and radio communications.

- During observations of 'A' ESW pump maintenance, the team noted that the work area was loud which inhibited face-to-face and radio communications.

- The team observed that the control room upper fuel pool water level monitor was located behind the reactor operator console and could not be viewed by the control room operators without leaning over the P680 panel.

- The team observed that the refueling tag board was located in a cubicle adjacent to the at-the-controls horseshoe area. This location inhibited face-to-face communications between the at-the-controls reactor operator and the refuel communicator maintaining the tag board.

- The team observed that reactor operators had to lean over feedwater and condensate panels to access the digital feedwater touch-screen controls.

The team also identified some examples in which equipment labels were either difficult to read or were missing. However, these examples were relatively limited in number and had not resulted in any actual adverse consequences.

3.4 Procedure Quality

a. Inspection Scope

The team evaluated the extent to which procedure quality had contributed to previously identified performance issues through the review of CRs, root cause reports, licensee event reports, NRC inspection reports, self-assessments, and other documentation. The team reviewed a sample of procedures involved in previous performance problems to assess the technical adequacy of those procedures. The reviews included a verification that the procedure steps could achieve the required system performance for normal, abnormal, and emergency operating procedures. Procedures were also reviewed to determine whether the activity was accomplished within the plant design basis and regulatory requirements, and that procedure inadequacies did not exist that would result in an initiating event.

The team reviewed maintenance procedures to ensure that they were sufficient to perform the maintenance task, that they included independent quality verification of important attributes, and that they resulted in the task being performed consistent with the equipment vendor instructions and specifications. A sample of important vendor manuals were also reviewed to ensure they were complete and up-to-date. The team reviewed the effectiveness of the licensee in ensuring current copies of documents were in place in the working files and that procedures affected by modifications or industry experience were updated in a timely manner.

The team reviewed a number of procedures utilized during in-field activities and determined whether these procedures were current. The team also reviewed the procedure change process to determine whether it was in accordance with regulatory requirements; whether appropriate personnel were involved in the development, review, and approval of procedure changes; and whether human factors principles were appropriately considered to increase the likelihood that the procedure would be easy to use and followed. A sample of procedure revisions subject to the 10 CFR 50.59 process were also reviewed to determine whether these changes were properly evaluated. The team also reviewed the adequacy of controls for developing special or complex procedures to ensure that they were adequately validated and discussed with the plant personnel prior to implementation.

The team evaluated a sample of temporary procedure changes to ensure the changes were reviewed and approved in accordance with TS requirements and that the changes were consistent with the plant design and licensing bases. The team reviewed night orders, WOs, and other documents to ensure that they did not result in uncontrolled procedure changes.

The team also reviewed a sample of CRs involving procedure quality to assess the effectiveness of the licensee’s corrective actions.

b. Observations and Findings

The team concluded that licensee’s procedures to safely control the design, maintenance, and operation of the plant were adequate, but warranted continued management focus, direction, and resource support. The team identified that procedure adequacy issues were not limited to any specific area, but were generally widespread and had been accepted by the staff as a normal everyday occurrence.

Through a review of licensee CRs generated in 2005, the team performed an analysis of procedural adherence issues, procedure adequacy issues, and procedural enhancement requests. Of the procedure-related CRs reviewed, 64 CRs documented instances of inadequate or poor procedural quality; 38 CRs requested enhancements or improvements to procedures to address potential human error traps; 29 CRs were determined to have resulted in or have the potential to result in an adverse impact on plant equipment reliability and safety; and 47 CRs documented an actual non-compliance with plant or corporate procedures. The team also noted that all of the 31 procedure-related CRs generated prior to March 21, 2005, were associated with NRC findings and observations.

Despite the recent recognition of these trends and weaknesses, data which reflected a negative trend in procedure adequacy issues previously existed and had been documented in CRs.

For example, licensee personnel recognized an adverse trend and potential problem with accurate preparation and review of plant procedures as evidenced by CR 05-02823 which was generated in March 2005 and stated, in part, that “Procedures that have been approved and released to the work force create an error-likely situation. The number and breadth of the events identified in this CR suggests a culture may exist that does not challenge procedure accuracy." Subsequently, CR 05-03039 was generated on April 5, 2005, and reinforced this position. This CR stated, in part, that, "The team approach to upgrading procedures is not catching many inadequacies as evidenced by subsequent CRs noting deficiencies.”

The licensee’s procedural effectiveness metric measured the number of procedures containing errors, i.e. the quality of the procedures. This metric had been “red” since it was initiated in January 2005. The trend had been increasing since February. The results for April indicated an inadequate procedure was being identified, on average, on a daily basis.

During this inspection, the team identified the following process-related vulnerabilities in the procedure adequacy area:

- The team determined that the licensee discontinued biennial procedure reviews in the late 1990s. The licensee concluded that these reviews were unproductive since other programs provided an equivalent review of plant procedures. The team identified that the procedure change requests that had been generated as a result of these equivalent reviews that were conducted resulted in only the revision to specific items in any given procedure, rather than human factors or format improvements. The team also identified that a review of the effectiveness of the equivalent method had not been conducted.

- When a procedure could not be completed as desired or required that steps be coded "N/A” [not applicable], a senior reactor operator or a department supervisor, as the "Authorizing Authority" could generate a procedure “work around” using NOP-LP-2601, "Procedure Use and Adherence;” OAI-0201, "Operational Evolution Order;" or NOP-SS-3001, "Procedure Writing," section on "Limited Use - Simple Change Processes.”

- Procedures categorized as "In Field Reference" vice "Step by Step" allowed the bulk of the plant procedures to be reviewed anytime during the shift the task was expected to be performed. A large number of procedures associated with plant configuration control appeared to be "In Field Reference" including all SOIs. A recent upgrade to SOIs did not identify the “Reference Use” classification of these procedures as a vulnerability.

- During a modification review, the team identified that WO 00-2080 instructions were not performed as written. Specifically, step 13 of WO 00-2080 required point-to-point wiring checks be performed, and Attachment 1, "Point-to-Point Checks for E12-F011A," contained detailed instructions for these checks. However, the WO work-in-progress log stated that the maintenance technicians had performed the checks differently than specified in Attachment 1, and that a maintenance supervisor had concurred with the deviation. The team identified that the written work instructions were not revised, as required by PAP-0905, "Work Order Process." The licensee entered this issue into their CAP as CR 05-03594. If a WO instruction could not be performed as written, PAP-0905 did not address how the worker or work supervisor could make revisions to in-progress field work. If a WO instruction required revision, then a work-stop would be required, and the WO returned to work planning for revision. The team concluded that the licensee’s work control process did not provide clear, unambiguous guidance for revision to in-progress field work.

- CR 03-4912, "EDG Reverse Power Trip," identified less than adequate procedural guidance for the use of a "Step N/A" as a contributing cause. Corrective Action (CA) 03-04912-28 required that Operations "strengthen implementation of programmatic requirements." The action implemented was to "clarify expectations" for procedure deviations, and was informal. The corrective action closure document stated that the clarity of expectations had been effective, because there were significantly fewer procedure steps being marked N/A.

  The team determined that CA 03-04912-28 had not effectively corrected inappropriate marking of steps as N/A. Specifically, in 2004, the licensee’s QA department identified several instances where the intent of a procedure had been unexpectedly changed, when a step was marked N/A (CR 04-01149). In additional, in 2004, at least 27 CRs were initiated for procedures that had steps marked as N/A.

- NOP-LP-2601, Section 4.5, "When Procedure Steps Do Not Apply," specifically prohibited marking a step N/A, if skipping the step would change the intent of the procedure. The team noted that the licensee’s administrative practice of allowing steps to be marked N/A required operators to make technical determinations of procedure intent. This practice appeared to be a de facto one-time procedure revision that bypassed the formal procedure revision process, did not require any interfacing discipline or engineering review, and did not require any 10 CFR 50.59 review.

In addition, the following specific issues associated with procedure adequacy were identified:

- During this inspection and as detailed in Attachment 1 of this report, the team identified that licensee personnel failed to include appropriate QC hold points in ESW pump coupling assembly steps, which resulted in an inadequate work procedure. (Attachment 1, Item 1.14)

- During this inspection, and as detailed in Attachment 1 of this report, the team identified that licensee personnel failed to properly address operating experience and prevent the oil feed supply from protruding into the oil reservoir housing of oilers associated with safety-related equipment. In particular, and as related to procedure adequacy, procedure revisions to address the issue failed to provide clear guidance for preventing the oil feed supply nipple from protruding into the oil housing. (Attachment 1, Item 1.12)

- As discussed in IR 05000440/2005005, maintenance procedures for overhauling safety-related breakers failed to contain appropriate guidance to refurbish breakers within the vendor's specified time frames or provide reasonable alternative PM practices to ensure that safety-related breakers remained operable.

- As discussed in IR 05000440/2005005, maintenance procedures failed to contain appropriate guidance to measure and monitor critical dimensions identified by the vendor.

- During this inspection, and as discussed in Section 7.5 of this report, licensee personnel identified that while performing SOI-E12, Section 7.14.2, it was possible to inadvertently drain the suppression pool to the auxiliary building sump.

Recently, as part of the Perry PII, the licensee implemented an effort to review and upgrade more than 120 critical maintenance procedures and improve the format and content of SOIs. The recent initiative to improve procedural quality may present a challenge to the licensee's organization. Near the end of the inspection, the operations department alone had a backlog of about 850 procedure changes. The mechanical maintenance department had more than 1200 procedures that were not as yet identified for upgrade. The resources required to perform procedural improvements could be significantly challenged to meet the management expectations for implementing procedural improvements at the current staffing levels. At the end of this inspection, this effort was still ongoing and the team did not have an opportunity to evaluate the licensee's progress.

3.5 Equipment Performance

a. Inspection Scope

The team reviewed various maintenance-related issues for the selected systems to evaluate the effectiveness in identifying the causes and extent of equipment problems as well as in developing and implementing corrective actions. Additionally, an assessment of the implementation of maintenance rule requirements was conducted. The team reviewed maintenance-related documents, observed maintenance activities, and conducted plant tours to assess the effectiveness of the licensee in entering maintenance issues into the CAP. The team also reviewed open CRs and corrective maintenance WOs for the selected systems to assess their potential impact on operability.

The team also reviewed surveillance tests and post-maintenance tests to assess the effectiveness of the licensee in specifying appropriate acceptance criteria and to determine whether the licensee’s controls to restore equipment to operation following testing and maintenance were effective. The team also reviewed the scope of the calibration program for the selected systems and sampled system instrumentation loops to ensure instrumentation important to safety was included. Additionally, the team reviewed the preventive maintenance programs for the selected systems to assess program adequacy and to determine whether design document, vendor manual, and generic communication information were appropriately incorporated into the maintenance program. Observations of in-progress maintenance and testing on the selected systems were conducted.

The team also observed a number of maintenance and testing activities during the inspection. During those observations, the team reviewed the system operating procedures and for cases in which special equipment was required to perform those procedures, the team determined whether the equipment was available, in good working order, and that the knowledge level of the operators was adequate concerning the equipment location and operation. The team also conducted interviews with licensee personnel, including engineering personnel who had an input into maintenance-related activities, to determine how the system was operated, whether that operation conflicted with the intended safety function, and whether engineering input was at an appropriate level to ensure safe and reliable plant operation.

For example, the team reviewed the licensee’s program and procedures used to ensure that the ECCS piping was filled with water as required by TS 3.5.1.1. The team performed field walkdowns, interviewed various plant personnel including the ECCS system engineer, operators, and members of the root cause evaluation team for the August 14, 2003, Division 1 LPCS/RHR 'A' waterleg pump air-binding event. In addition, on April 2, 2005, the team observed plant operators performing a partial system fill and vent of the “B' RHR train in accordance with SOI-E12, "Residual Heat Removal System.” The team also reviewed surveillance procedure SVI-E12-T1182-B, "RHR B LPCI [low-pressure coolant injection] Valve Lineup Verification And System Venting," used for monthly venting of the 'B' ECCS system train.

b. <u>Observations and Findings</u>

In the area of equipment performance, the team acknowledged that the licensee had completed numerous efforts to improve equipment performance. In addition, improved engineering support and management oversight of the plant material condition and equipment performance were noted. Several additional improvement initiatives were scheduled and ongoing. Examples included the installation of a digital feedwater control system to reduce scram frequency; replacement of the 'B' ESW pump and motor; completion of various fuel reliability improvements, such as new feedwater booster pump strainers, installation of new channels in 111 fuel bundles to eliminate bowing concerns, and installation of 288 new fuel bundles with improved debris shield design; modification of LPCS piping to ensure proper venting to reduce water hammer concerns; modification of the EDG exhaust system to eliminate long-standing problems with the EDG testable rupture discs; repairs to the main generator stator; completion of 65 safety-related and nonsafety-related 10-year breaker refurbishment; initiation of ultrasonic testing of non-ventable ECCS piping for air voiding concerns; modification of the safety relief valves filtering circuits to reduce the possibility of inadvertent opening; and the completion of system health and latent issues reviews.

However, the team identified numerous examples which indicated that the resolution of degraded equipment problems and implementation of the CAP continued to challenge the organization. The following specific issues related to the area of equipment performance were identified during the inspection:

- During this inspection and as detailed in Attachment 1 of this report, the team identified repetitive failures of the Division 1 and Division 2 SLC relief valves to satisfy as-found lift setpoint acceptance criteria. (Attachment 1, Item 1.1)

- During this inspection and as detailed in Attachment 1 of this report, improper bolts were installed in a drywell supply fan resulting in a failure. (Attachment 1, Item 1.3)

- During this inspection and as detailed in Attachment 1 of this report, the team identified that licensee personnel failed to implement adequate corrective actions to address air-binding of the LPCS/RHR 'A' waterleg pump and failed to identify an additional air void that could have affected the RCIC system until operating experience was received and reviewed. (Attachment 1, Item 1.4)

- During this inspection and as detailed in Attachment 1 of this report, the team identified that licensee personnel failed to implement adequate corrective actions in a timely manner to address the inappropriate use of “Never-Seez” in safety-related applications which resulted in degraded MOV performance. (Attachment 1, Item 1.5)

- During this inspection and as detailed in Attachment 1 of this report, the team identified that licensee corrective actions to address a Division 2 EDG leak were untimely and adversely impacted the reliability of the EDG. (Attachment 1, Item 1.9)

- During this inspection and as detailed in Attachment 1 of this report, the team identified that licensee personnel failed to recognize and correct the inability of RWCU PCIVs to close under all normal and abnormal conditions. (Attachment 1, Item 2.1)

- As discussed in IR 05000440/2005005, licensee personnel failed to incorporate industry operating experience into PM activities resulting in a trip of the 'A' reactor recirculation pump low frequency motor generator and subsequent manual scram of the reactor on December 23, 2004.

- During a containment walkdown, the team identified three hydraulic control units (HCUs) with directional control valve identification tags attached to the solenoid valve cable which could interfere with the position indication limit switch operation for the scram valve. As an immediate corrective action, licensee personnel performed a detailed walkdown of all HCUs, identified 10 additional interference items, and re-positioned the tags to address the issue. The team also identified that previous industry operating experience existed on HCU directional control valve and scram valve interference. Licensee personnel subsequently determined that the operating experience had not been reviewed.

3.6 Configuration Control

a. Inspection Scope

The team reviewed operability evaluations performed for the selected systems to assess technical adequacy and to ensure that they did not result in plant operation outside of the design and licensing bases. The team reviewed temporary modifications for the systems to evaluate whether they had been reviewed and approved by appropriate personnel and that controls were in place to limit the duration of the installation. Additionally, the team determined whether procedures and drawings were updated where necessary. The assessment included a review of selected configuration control issues from the CAP database to assess the adequacy of the licensee's problem identification and resolution program.

The team performed detailed walkdowns of the Division 1 and Division 2 EDGs and support systems, and the 'A' and 'B' trains of the RHR system, as well as other systems, to determine whether the as-built configurations and lineups were consistent with plant procedures, drawings, UFSAR and DBDs. The team also assessed the material condition of the system and support system components to determine if any conditions existed that could adversely impact operability. Additionally, the team performed a verification that system components were properly labeled, cooled, and lubricated to support the performance of their design requirements and that power was available and correctly aligned to support automatic activations where appropriate. The team also reviewed selected system instrumentation to determine whether it was properly installed and calibrated. The team reviewed overall cleanliness, control of ignition sources and flammable material in the vicinity of the systems, and control of temporary storage of materials and equipment to determine whether they impacted equipment operation or access by plant operators.

The team reviewed the backlog of corrective and preventive maintenance for the systems to assess whether any items or combinations could impact equipment operability. The team assessed the process for controlling maintenance, including the assessment of risk and the inclusion of emergent work into the schedule. A sample of tagouts were reviewed to assess the adequacy of the configuration for the planned work and the methods for controlling equipment status changes, including the control of entry and exit from TS action statements. A walkdown was performed to independently determine whether tag placements and component alignments were correct. Long-term tagouts, control room deficiencies, operator workarounds and equipment deficiencies were reviewed to assess the significance of these conditions. The review included an assessment of work control procedures for the control of hot work (welding, open flame, etc.) and the control of scaffolding in the vicinity of safety-related and risk-significant operating equipment. The team also reviewed the process for performing maintenance using the Fix-It-Now team.

The team reviewed primary and secondary system chemistry controls to assess their effectiveness in preventing degradation of the RCS pressure boundary. The inspection included a review of the last 6 months of reactor coolant and feedwater system chemical analyses records, trends of water quality data and corrective actions taken when chemical variables exceeded established limits. The adequacy of the licensee's measures to prevent the introduction of chemical contaminants into the primary and secondary coolant water and measures to detect any inadvertent contamination were also reviewed.

The team reviewed the results of the Perry PRA focusing on the RHR system and the EDGs. The team determined whether the PRA was being maintained to reflect actual system conditions regarding system capability and reliability through a review of the operating performance history of the systems compared to the actual out-of-service times assumed in the licensee's PRA. The team also reviewed the licensee's efforts to integrate preventive and corrective maintenance to minimize unavailability.

Temporary modifications for systems were also reviewed to ensure proper installation in accordance with design information.

b. <u>Observations and Findings</u>

b.1 <u>Summary of Observations</u>

The team agreed with the licensee's assessment, as stated in the Perry PII - Configuration Management Program Review, that continuing configuration control problems were primarily the result of "inappropriate implementation of the procedural requirements rather than the result of configuration management procedural shortcomings," and that the primary long-term concern was "the absence of (an) integrated program to ensure the Perry Configuration Management Program is in a condition to continue to support the safe operation." However, given the numerous errors associated with equipment misalignment identified during this inspection, as well as multiple errors associated with scaffolding erection, the team concluded that an adequate evaluation of the root cause and implementation of corrective actions to address configuration control errors had not been accomplished.

The team determined that the licensee lacked vigor in its efforts to resolve latent configuration control issues. Several licensee-identified issues had not been corrected, and contributed to configuration control short-comings. Examples included uncorrected plant operating procedure errors, uncorrected UFSAR discrepancies, and improperly tracked degraded and nonconforming conditions. The team noted that at the time of the inspection there was a backlog of over 800 plant-operating procedure problems awaiting correction, with limited resources dedicated to resolve them. The team also noted that between 1998 and 1999, an UFSAR validation project identified 7000 UFSAR discrepancies, and over 3000 have yet to be corrected. Although most of these discrepancies were administrative in nature, some required technical evaluation to determine their effect on plant safety. The licensee had no definitive schedule for resolving these discrepancies, and was unable to provide the team with evidence that the safety determinations were performed using criteria specified in 10 CFR 50.59, "Changes, Tests, and Experiments." As described in CR 03-05789, in 2003 the licensee identified that degraded and nonconforming conditions of SSCs important to safety were not evaluated or corrected using the criteria in Generic Letter 91-18. The team noted that although safety systems were currently operable, corrective actions for several degraded or nonconforming conditions were not complete, the oldest of which was initiated in 2001.

The team concluded that the overall material condition of plant equipment was satisfactory, although some material condition issues were identified during this inspection. The team also identified numerous minor material condition issues such as oil and valve packing leaks, which warranted the licensee's attention.

b.2 <u>System Walkdown and Configuration Control Review Results</u>

Numerous configuration control errors were identified during system walkdowns or as a result of self-revealing events. The following specific configuration control issues occurred recently:

- During this inspection and as detailed in Attachment 1 of this report, the team identified that licensee personnel failed to adhere to the At-Risk-Change procedure used for the modification of safety-related equipment. As a result, the configuration of the Division 1, 2, and 3 EDGs was not properly controlled and insulation was inappropriately hung on the EDG exhaust missile shield and ventilation exhaust piping without considering the EDGs to be inoperable. (Attachment 1, Item 1.6)

- During this inspection and as detailed in Attachment 1 of this report, the team identified that licensee personnel failed to correct an issue regarding the installation of scaffolding erected near safety-related equipment which did not meet the seismic bracing or clearance criteria of licensee procedures. As a result, the team identified unapproved scaffolding in the Division 1 EDG room. (Attachment 1, Item 1.10)

- During this inspection and as detailed in Attachment 1 of this report, the team identified that licensee personnel failed to adequately review available industry operating experience information and failed to identify degraded oil bubblers that were improperly configured and could have adversely impacted the operability of both ECCW pumps. (Attachment 1, Item 1.12)

- During this inspection and as detailed in Attachment 1 of this report, the team identified that licensee personnel failed to identify and correct numerous permanent structures that did not meet containment wall clearance requirements. (Attachment 1, Item 1.2)

- During this inspection and as detailed in Attachment 1 of this report, the team identified that licensee personnel improperly performed a procedure step for the verification of the position of RCIC system electrical disconnects which resulted in the incorrect alignment of equipment. (Attachment 1, Item 3.2)

- During this inspection and as detailed in Attachment 1 of this report, the team identified that maintenance personnel improperly performed a procedure step for verification that jumpers had been removed from an electrical cabinet which resulted in the incorrect alignment of equipment. (Attachment 1, Item 3.3)

- As discussed in IR 05000440/2005002, on February 27, 2005, during a local leak rate test, RHR 'A' suppression pool suction valve 1E12-F004A was inappropriately opened with the 'A' RHR system drained. As a result, the suppression pool drained through an open drain valve to the auxiliary building equipment drain sump. The draining was terminated when the suction valve was closed, but only after about 8500 gallons had been inadvertently drained from the suppression pool.

- As discussed in IR 05000440/2005002, on March 10, 2005, during RFO10 refueling activities, the control room senior reactor operator (SRO) inadvertently withdrew control rod 58-35 from position 00 to position 02 while attempting to verify the position of all rods in the core. Following this manipulation, the SRO immediately realized the error and after obtaining a peer check from a reactor operator immediately re-inserted the control rod to its previously fully inserted position.

- During this inspection, on March 1, 2005, during the performance WO 200073510 which specified the removal of RCIC exhaust vacuum breaker check valve 1E51F0079, an adjoining RCIC check valve, 1E51F0081, was improperly removed instead.

- During this inspection, on March 2, 2005, during the performance of WO 200094531 which specified the removal and replacement of RHR system orifice plate 1E12D0001C, the wrong RHR system orifice plate was removed and replaced.

- The team reviewed ECP 04-0092 (Division 1) and ECP 04-0092-01 (Division 2), "EDG Vibration Switch Removal." The review included the ECP, interim drawing change notices (IDCNs), as-built drawings, affected documents and procedures, design interface reviews, and 10 CFR 50.59 evaluation. In addition, the team performed walkdowns of the EDG, to assess whether the design intent had been adequately implemented in the field. The team concluded that the vibration switches and associated trip function had been adequately removed from the EDG and its control system. The team identified several minor configuration control issues that were previously unrecognized by licensee personnel. The licensee entered these issues into their CAP as CRs 05-03103, 05-03108, and 05-03111. The issues included:

- The design function for R43-F500A changed from a normally open instrument root valve, to a normally closed pressure boundary isolation valve, for the EDG pneumatic trip system. The ECP required that R43-F500A be closed and tagged "Do Not Open." The team found R43-F500A closed, but not tagged as required.

- Drawing 302-0349 was updated differently than indicated on the approved IDCN, such that R43-F500B was incorrectly labeled as abandoned.

- There were component nomenclature differences (i.e., labeling) between the Division 1 and Division 2 drawings.

- The ECP required R43-F500A be administratively controlled closed. The Affected Documents List identified IMI-E04-08, "I&C Valve Line-up Instructions," as requiring revision. The team identified that the valve line-up procedure had not been revised, and no revision request was pending.

- The Division 1 EDG control room and local alarm response procedures (ARI-H13-P877-0001-F2 and ARI-H51-P054A) had not been revised although 6 months had elapsed following work completion. However, the Division 2 EDG procedures had been revised. The Division 1 EDG procedure change requests were prioritized as "Category 6 - Activities that can be deferred indefinitely or are associated with DCPs."

b.3 <u>Maintenance Work Control Review Results</u>

The team identified that the licensee had documented inadequate work package reviews, lack of schedule adherence, prolonged out-of-service times, and poor organization interface issues following previous assessment activities. Twenty-one CRs written in late 2004 and early 2005 indicated that an increased organization commitment was warranted to implement needed improvements.

The team reviewed preventive maintenance grace utilization curves and identified that the 12 month average of PMs with a frequency of less than 2 years had greater than 70 percent of the PMs scheduled in their grace period. For PMs with a frequency of greater than 2 years, 50 percent were scheduled in their grace period. Although many of these PMs were associated with nonsafety-related systems, the team concluded that this scheduling practice could burden the workforce and could, if left uncorrected, have an adverse impact on plant reliability.

Surveillances for May 2005 were reviewed and most were already into the grace period. However, no evidence of the inability to perform a safety-related function was identified. Like PMs however, the team concluded that continued use of the grace period to accomplish routine surveillance activities increased the likelihood of a missed TS surveillance.

The team identified that the work management organization had only one work week manager assigned and no long-range cycle scheduler at the beginning of May 2005. In addition, the team identified that CRs had been generated which documented that work scheduling and planning meetings had, at times, not been attended as required by many department representatives.

The team concluded that a lack of dedicated work management resources appeared to impact the licensee's ability to accomplish work in a timely manner. The team also concluded that although adequate, the Work Management program required significant management focus and attention.

b.4 Chemistry Controls

The licensee's primary and secondary chemistry procedures and analyses were found to be satisfactory and in accordance with the Electric Power Research Institute (EPRI) Boiling Water Reactor (BWR) guidelines. Appropriate corrective actions, in accordance with EPRI BWR guidelines, were found to have been implemented to restore water quality when transients or other upset conditions occurred.

While reviewing feedwater and reactor coolant system analyses results, the team noted that Chemistry personnel appropriately trended metallic elements such as cobalt, chromium, zinc, copper, and iron. Conductivity, chlorides, sulfates, and dissolved oxygen were also tracked and trended, particularly following chemistry excursions directly related to power transients or RWCU system maintenance activities.

During a review of Chemistry Procedure REC-0104, "Chemistry Specifications," Revision 14, the team determined that although the procedure was comprehensive and contained appropriate guidance to address off-normal chemistry conditions, the procedure was difficult to use. In particular, the majority of the procedure was comprised of a compendium of tables defining parameter limits with a right-hand column which linked a numbered prescribed action to a given initial off-normal condition. These prescribed actions, 185 in all, did not directly follow the parameter tables, but were on a separate list near the back of the procedure.

b.5 Fission Product Barrier Assessment

Because problems had not been previously identified, this area was not specifically reviewed during the inspection.

b.6 Probabilistic Risk Assessment Review

The team reviewed the licensee's updated PRA results, including system notebooks for the RHR system and the EDGs. The PRA had been last updated in April 2004 to reflect current system configurations and to incorporate the most recent availability and reliability data. The licensee performed updates to the PRA in accordance with plant procedures generally every refueling cycle. The team determined that the system modeling for the selected systems accurately reflected the actual system conditions in the plant.

The team reviewed calculation DB-003, "Unavailability Due to Test and Maintenance," Revision 4, which was used in the PRA update performed in April 2004. The team verified that out-of-service times for the RHR and EDG systems through the most recent operating cycle were used in the calculation and reflected actual equipment performance.

3.7 Emergency Preparedness

3.7.1 Emergency Preparedness Performance Overview

Performance in the Emergency Preparedness area has been characterized by Green performance indicators (PIs) in the three Emergency Preparedness PI areas of drill/exercise performance, ERO drill participation, and Alert and Notification System. However, two White findings, one associated with an undue delay in declaring an actual Alert emergency condition on April 24, 2003; and another associated with an undue delay in obtaining emergency dose assessment information during an Alert on July 20, 2004, had been identified.

White Finding - Undue Delay in Declaring Emergency Condition

As discussed in IR 05000440/2004003 dated January 23, 2004, the NRC provided the licensee with the final results of a significance determination of a preliminary White finding identified in IR 05000440/2003006. The inspection finding was assessed using the significance determination process and was preliminarily characterized as White (i.e., a finding with low to moderate increased importance to safety, which may require additional NRC inspections). This preliminary White finding concerned the failure to follow the requirements of the Perry Emergency Plan during an Alert level event on April 24, 2003.

The finding involved an undue delay in declaring an actual emergency condition on April 24, 2003, when the SM did not properly classify the event in a timely manner in accordance with the emergency plan when damage to irradiated fuel caused a high alarm on the fuel handling building ventilation exhaust gaseous radiation monitor. This finding was preliminarily classified as White because it involved a failure to implement a risk significant planning standard. This preliminary White finding was associated with an apparent violation of 10 CFR 50.47.

After considering the information developed during the inspection, the NRC concluded that the inspection finding was appropriately characterized as White. The NRC also determined that the failure to properly implement the standard emergency classification and action level scheme resulting in an undue delay in declaring an actual emergency was a violation of 10 CFR 50.47(b)(4).

As discussed in NRC Supplemental IR 05000440/2004004 dated February 10, 2004, the NRC reviewed the licensee's root cause evaluation and corrective actions for this issue. No findings of significance were identified and the White finding was closed.

White Finding - Failure to Obtain Timely Emergency Dose Assessment

As discussed in IR 05000440/2004016, dated December 23, 2004, the NRC completed a preliminary review of a July 20, 2004, Alert at the PNPP. The finding was related to the licensee's failure to obtain an emergency dose assessment within 15 minutes of the event as required by the Emergency Plan. This finding was assessed using the Emergency Preparedness Significance Determination Process and was preliminarily determined to be White. This finding was also determined to be an apparent violation of NRC requirements. Specifically, 10 CFR 50.47(b)(4) required that the licensee use a standard scheme of emergency classification and action levels. The emergency plan required performance of a Computer Aided Dose Assessment Program (CADAP) run within 15 minutes in order to classify this event. Contrary to this requirement, no CADAP run was provided until 2 hours and 40 minutes after the Alert declaration.

After considering the information developed during the inspection, the NRC concluded that the inspection finding was appropriately characterized as White. The NRC also determined that the failure to properly implement the standard emergency classification and action level scheme resulting in an undue delay in performing an emergency dose assessment was a violation of 10 CFR 50.47(b)(4). An NRC Supplemental IP 95001 inspection is planned to review the licensee's root cause evaluation and corrective actions.

Exercise Performance

As discussed in IR 05000440/2004014 dated October 27, 2004, the NRC reviewed the October 5, 2004, biennial emergency preparedness exercise, focusing on the risk-significant activities of emergency classification, notification, and protective action decision-making, as well as the licensee's implementation of accident mitigation strategies in the following emergency response facilities:

- Control Room Simulator;
- Technical Support Center (TSC);
- Operations Support Center (OSC); and
- Emergency Operations Facility (EOF).

The team also assessed the licensee's recognition of abnormal plant conditions, transfer of responsibilities between facilities, internal communications, interfaces with offsite officials, readiness of emergency facilities and related equipment, and overall implementation of the licensee's emergency plan.

The team attended post-exercise critiques in the TSC, OSC, and EOF to evaluate the licensee's initial self-assessment of its exercise performance. The team later met with the licensee's lead exercise evaluators to obtain the licensee's refined assessments of its exercise participants' performances. These self-assessments were then compared with the team's independent observations and assessments to determine the licensee's ability to adequately critique its exercise performance.

No findings or significant observations were identified as a result of this inspection. Therefore, the team did not request that an emergency drill be conducted for the IP 95003 inspection.

Scope of IP 95003 Review in the Emergency Preparedness Area

To satisfy the overall objectives of the IP 95003 inspection, the team used the guidance in IP 95003 and reviewed the following key attributes during this phase of the inspection:

- Problem Identification and Resolution
- Emergency Response Organization Staffing
- Emergency Plan and Procedure Quality
- Emergency Facilities and Equipment
- Emergency Response Organization Performance
- Emergency Preparedness Off-Site Interface

3.7.2 Problem Identification and Resolution

a. Inspection Scope

The team evaluated the effectiveness of corrective actions for emergency preparedness (EP) performance issues to determine whether identified problems were appropriately reviewed, prioritized, and resolved in an adequate and timely manner. The review included an assessment of action items in the licensee's CAP, QA audit reports, and various self-assessments and exercise reports generated from April 2002. In addition, interviews were conducted with the EP Manager and individuals responsible for overseeing the CAP within the EP group.

b. Observations and Findings

The team identified several examples where a relatively high threshold for classifying deficiencies in the CAP resulted in potentially inadequate or minimally acceptable evaluations of those deficiencies. For example, no apparent or root cause evaluation was performed for the following:

- Condition Report 04-04827 identified that the removal from EAL GA2 of the reactor cavity as a fuel pool was a potential decrease in the effectiveness (DIE) of the Emergency Plan.

- Condition Report 04-04825 identified that chemistry sampling criteria from EALs HA1 and HA2 were removed since the samples could not be obtained within the required time frame. Although not a DIE, the question of how an EAL could be written which physically could not be implemented was raised, but was not addressed through an apparent or root cause evaluation.

- Condition Report 04-04171 identified the inadvertent removal from EALs AS1 and IS1 of the lines which function as "AND" connectors between EAL conditions, both of which must be met to reach the given EAL threshold. Although this was a typographical error, the error propagated through three revisions of procedure EPI-A1, "Emergency Action Levels," and raised the question of the effectiveness of the procedure review process which was not addressed through an apparent or root cause evaluation.

In each of these cases, the deficiencies were classified as conditions adverse to quality, but were considered to be sufficiently straightforward to resolve with no additional evaluation of the causal factors involved. The licensee generated CR 05-03405 to further evaluate the need for more detailed analysis of the aforementioned EAL deficiencies.

3.7.3 Emergency Response Organization Staffing

a. Inspection Scope

The team reviewed the licensee's emergency response organization to ensure the minimum on-shift staffing met the applicable regulatory requirements and that staffing was sufficient to fill positions needed in the emergency facilities. The team also reviewed drill records and call-in procedures to determine if augmentation and off-hour drills were held as required by the Emergency Plan, whether augmentation goals were met, and whether off-shift personnel were available, if needed. In addition, interviews were conducted with ERO responders to determine whether their understanding of the call-out process and their responsibilities for reporting to their facilities during an event were consistent with licensee procedures and expectations. The team determined whether the licensee was able to meet Emergency Plan goals for activation by implementing NRC Inspection Procedure 71114.03, "Emergency Response Organization Augmentation." At the request of the team, the licensee conducted an unannounced off-hours augmentation drill to verify the ability of the ERO to staff the TSC, OSC, and EOF in a timely manner during an emergency.

b. Observations and Findings

May 19, 2005, Unannounced Augmentation Drill and Review of Licensee Drill Critique

On May 19, at 4:00 am, the licensee conducted an unannounced off-hours augmentation drill to verify the ability of the ERO to staff the TSC, OSC, and EOF in a timely manner during an emergency. The licensee simulated the declaration of a Site Area Emergency (SAE) and notified the on-call ERO through the normal callout pager system, who were then required to report to the site and staff the emergency facilities.

The objectives of the drill were as follows:

Drill Objective #1: Demonstrate the ability of the on-call ERO personnel, or alternates, to declare the OSC operational within 60 minutes of an SAE in accordance with the Emergency Plan.

Drill Objective #2: Demonstrate the ability of the on-call ERO personnel, or alternates, to declare the TSC operational within 60 minutes of an SAE in accordance with the Emergency Plan.

Drill Objective #3: Demonstrate the ability of the on-call ERO personnel, or alternates, to declare the EOF operational within 90 minutes of an SAE in accordance with the Emergency Plan.

Drill Objective #4: Demonstrate satisfactory Emergency Preparedness Table 5-1 augmentation response times.

The inspectors observed the drill and assessed licensee performance in meeting the following Emergency Plan timeliness goals:

- Staff arrival goals: 45 minutes for the TSC/OSC (15 minutes to notify, 30 minutes to report in), and 75 minutes for the EOF (15 minutes to notify, 60 minutes to report in). This was intended to verify that all Table 5-1 30-minute and 60-minute responders could report to the site in the required time.

- Facility operational goals: 60 minutes for the TSC/OSC, and 90 minutes for the EOF (15 minutes after staff arrival). This was intended to verify that the ERO could follow licensee procedures to make emergency facilities operational 15 minutes after all minimum staff were in place.

The licensee simulated the SAE declaration at 4:00 am and the on-call ERO pagers were activated at approximately 4:08 am. The 30-minute responders were expected to report by 4:45 am; 60-minute responders by 5:15 am. The weather was clear and calm, and therefore did not hinder ERO staff response.

<u>TSC Response</u>

Four responders failed to arrive in the required 45 minutes, as follows:

- Maintenance Coordinator: 4:47 (2 minutes late)
- Radiation Protection (RP) Coordinator: 4:52 (7 minutes late)
- Administrative Assistant: 4:50 (5 minutes late)
- Operations Advisor (OA): 5:02 (17 minutes late)
- The on-call Team 'A' responder never reported to the site so this position was filled by a back-up responder.

The TSC Operations Manager (OM) inappropriately assigned the OA duties to the Plant Technical Engineer (TE), such that the TE had responsibility for two response positions. The TE had an operations background, but was not presently qualified to fill the OA position. The OM made this decision at 4:58 am, just prior exceeding the goal for declaring the TSC operational, which expired at 5:00 am.

Additionally, an Electrical Engineer, who was a TSC 60-minute responder not necessary for the facility to be declared operational, called in to accept the position, but never reported to the site.

The team concluded that four TSC 30-minute responders failed to meet the staff arrival goal of 45 minutes, and one 60-minute responder failed to meet the goal of 75 minutes (the Electrical Engineer, who did not report to the site). The OM incorrectly assigned the

OA duties to the TE so that the TSC operational goal of 60 minutes could be met. The TE was not presently qualified to perform as the OA, and Emergency Plan Table 5-1 contained no provision to assign the duties of two augmented responders to one person. Therefore, the team concluded that the licensee failed to meet Drill Objective #2.

OSC Response

Four 30-minute responders failed to arrive in the required 45 minutes, as follows:

- OSC Coordinator: 4:46 (1minute late)
- RP Technician #1: 4:54 (9 minutes late)
- RP Technician #2: 4:55 (10 minutes late)
- RP Technician #3: 5:00 (15 minutes late)

Two 60-minute responders failed to arrive in the required 75 minutes, as follows:

- RP Technician #6: 5:19 (4 minutes late)
- RMT Leader #3: 5:35 (20 minutes late)

Additionally, the shift RP Technician assumed the OSC Coordinator (OSCC) position on an interim basis until the on-call OSCC reported to the site.

The team concluded that four OSC 30-minute responders failed to meet the staff arrival goal of 45 minutes, and two 60-minute responders failed to meet the goal of 75 minutes, including five out of nine RP Technicians and the on-call OSCC. The OSC was declared operational at 4:18 am by the shift RP Technician acting as the interim OSCC. Licensee procedures allow the OSC to be declared operational with only the OSCC present. Therefore, the team concluded that Drill Objective #1 was met.

EOF Response

The staff arrival goal was 5:15 am, 75 minutes following event classification. All ERO responders were present in the EOF by 4:54 am, and the facility was declared operational at 5:01 am, with a 5:30 am goal. Therefore, the team concluded that Drill Objective #3 was met.

The team concluded that since five TSC responders and six OSC responders failed to meet the staff arrival timeliness goal, that Drill Objective #4 was not met.

Licensee Drill Critique Review

The team reviewed self-assessment report 759PYRC2005, "2005 Emergency Response Organization (ERO) Off Hours Unannounced Drill," which evaluated the May 19, 2005, unannounced augmentation drill.

The report concluded that the objectives related to declaring the OSC and EOF operational were successfully met. However, the other two objectives were not successfully met. Specifically, the TSC was declared operational without meeting the requirements for minimum staffing. In addition, the augmentation time requirements for the Emergency Plan, Table 5-1 responders were not met in all cases.

The report also concluded that in the case of augmentation of RP personnel, the drill objectives were not fully demonstrated due to the method used to conduct the drill. Specifically, although management had the expectation that all RP individuals respond to the site during an actual plant event, the automatic paging system used for the drill did not permit this “all call” philosophy to be implemented.

In their critique, licensee personnel also established a 10-minute “grace period” or “adjustment factor” to account for early morning response delays and the increase in the stand-off distance from the plant due to an expanded no parking zone. At the end of this inspection, the team had not had an opportunity to completely review the basis for this adjustment factor. As a result, this issue is an URI (**URI 50-440/2005003-01**) pending a determination of whether the 10-minute adjustment factor was in accordance with the Emergency Plan.

<u>Other Findings and Observations</u>

The following additional issues concerning ERO staffing were identified:

- The RP Technicians carried pagers, but were not assigned to ERO on-call teams as 30-minute or 60-minute responders. Nine RP Technicians were required to respond in an emergency to meet ERO staffing requirements, five in 30 minutes and four in 60 minutes. The Dialogics callout system paged them all, and during a drill the RP Technicians call in to fill the nine positions. Once the positions are electronically filled, all other responders for those positions are informed that their response is not required. During the May 19, 2005, augmentation drill, five of the nine RP Technicians were late reporting to the site; three of five 30-minute responders and two of four 60-minute responders.

  Of the 27 RP Technicians, 16 resided within 30 minutes of the site, 8 resided within 60 minutes of the site, and 3 that resided more than 60 minutes from the site. The team identified that during a drill, five of the nine positions could be filled by Dialogics by personnel who resided more than 30 minutes from the site, resulting in the inability to staff the five 30-minute RP Technician positions within Emergency Plan staffing timeliness goals. Licensee personnel stated that this was not possible during an actual event since the RP Technicians adhered to an "all-call" management expectation that all responders respond to actual events, regardless of the number of other individuals also reporting. However, this was a management expectation and was not required by licensee procedures.

- RP Technicians were not specifically assigned to ERO teams and as such were not required to remain fit for duty or remain within the vicinity of the facility. Therefore, at any given time, a number of these responders could be outside the local area or engaged in leisure activities where they may not be fit for duty. This would not be known to plant management, since an accountability system to track their whereabouts had not been established. Of the 27 RP Technicians, 9 were required to respond in an emergency to meet Emergency Plan staffing goals. The possibility existed that a number of them could be outside the local area or not fit for duty, resulting in an insufficient number of RP technicians to fill all required ERO positions.

At the end of this inspection, additional information was required to determine whether the Emergency Plan could be properly and consistently implemented. Therefore, the two issues identified above are an URI (**URI 05000440/2005003-02**) pending additional NRC review.

- During this inspection and as detailed in Attachment 1 of this report, the team identified that the licensee failed to obtained required NRC approval in accordance with 10 CFR 50.54(q) when the licensee revised the Emergency Plan to potentially assign the shift Health Physics (HP) Technician as the interim OSCC. (Attachment 1, Item 5.1)

- The team determined that the licensee's required response times for Table 5-1 responders during three 2004 augmentation drills were not adequate to determine if the staff arrival timeliness goals were met. The Emergency Plan specified two response timeliness goals as follows:

  - Staff Arrival - 15 minutes for ERO notification, plus 30 minute response in accordance with Table 5-1 for TSC/OSC responders (45 minutes total); plus 60 minute response for EOF responders (75 minutes total).

  - Facility to be Fully Functional - an additional 15 minutes after staff arrival, i.e., 60 minutes for the TSC/OSC, and 90 minutes for the EOF.

  The licensee's required response times for the three 2004 augmentation drills only considered the facility operational goals of 60 minutes and 90 minutes. Although this was proper to verify the facility operational timeliness goal, it did not verify the staff arrival goals of 45 and 75 minutes. The licensee performed a more detailed review of keycard logs detailing when personnel entered the protected area, which indicated that several responders exceeded the staff arrival goals by up to 8 minutes. Although these times were not excessive, the team determined that the licensee was not aware in all cases that the goals had been exceeded and therefore had not adequately assessed staff arrival goals.

  The team also identified that the TSC electrical and mechanical engineers' (both 60 minute responders) response times were not monitored during the three drills, and the Chemistry Technician response time, a 60 minute responder, was not monitored during two of the three drills. Keycard logs indicated that these personnel did respond in a timely manner, but this issue also hindered the adequate assessment of augmentation drill results.

The licensee entered these staff augmentation issues into their CAP as CR 05-03271.

3.7.4 Emergency Plan and Procedure Quality

a. Inspection Scope

The team performed a review of Emergency Plan Implementing Procedure (EPIP) changes against the requirements of the Emergency Plan to determine whether any changes had decreased the effectiveness of the plan. In addition, a review of the EPIPs relative to the significant planning standards was performed. The team evaluated the 10 CFR 50.54(q) review documentation and applicable procedures to assess whether the method for reviewing the Emergency Plan and implementing procedure changes was adequate to correct deficiencies related to EPIP and maintaining Emergency Plan commitments in EPIP instructions.

b. Observations and Findings

The following issues concerning the Emergency Plan and related procedures were identified:

- During this inspection and as detailed in Attachment 1 of this report, the team identified that the Security Plan revision implemented on November 8, 2005, eliminated terms from the Security Plan and Security Event Checklists which must be used by the security shift supervisor (SSS) to communicate information to the SM for event classifications. This potentially impacted the accuracy and/or timeliness of classifications under EALs NU1 and NA1. (Attachment 1, Item 5.2)

- The team identified that procedure EPI-A7, Attachment 1, was revised to state that the OSC could be declared operational with only the OSC Coordinator present. This did not appear to meet the intent of Table 5-1 of the Emergency Plan which required other 30-minute augmentation staff to report to the OSC, i.e., three RP Technicians and two radiation monitoring teams, for a total of seven personnel. Additionally, Figure 5-1, "ERO Interim Phase," which was a block diagram of all required augmentation staff which reported to the OSC at an Alert classification (i.e., in 60 minutes), indicated that HP personnel, OSC repair teams, and radiation monitoring teams were present during this phase. Lastly, Section 5.2.1 of the procedure stated that the facility should be declared operational after determining available staff. The licensee documented this issue in CR 05-03685 for evaluation.

  The team concluded that there was undue emphasis on making the OSC operational in the required time instead of giving due consideration to the staff resources that were actually available. However, this was not considered to be a decrease in the effectiveness of the Emergency Plan since the additional staff must report in the required time period regardless of whether the facility was declared operational or not. The licensee generated CR 05-03407 to identify this issue in their CAP.

3.7.5 Emergency Facilities and Equipment

a. Inspection Scope

The team reviewed surveillance test records and maintenance procedures for offsite sirens, emergency pagers and communication equipment to determine if the tests were performed in accordance with regulations and Emergency Plan commitments and whether the facilities and equipment themselves were adequate. In addition, the team conducted an inventory of the emergency equipment located in the emergency facilities using the appropriate inventory checklists.

Observations and Findings

No deficiencies were identified.

3.7.6 Emergency Response Organization Performance

a. Inspection Scope

A review was conducted of the licensee's training program to ensure it was in compliance with the applicable regulations and the Emergency Plan. The team also conducted interviews and observed training to identify any weaknesses. In addition, the team reviewed reports for several recent training exercises to determine the adequacy of training and the ability to identify and correct exercise deficiencies in a timely manner.

b. Observations and Findings

Emergency Plan Change to ERO Requalification Requirements

The NRC approved the Emergency Plan, Revision 5, on August 16, 1985. In Section 8.1.2.2 of the Emergency Plan, the licensee committed to provide specialized training to the ERO which was delineated in Table 8-1 of the Emergency Plan, and consisted of several training modules for each position. For example, Emergency Coordinators (ECs) received classroom training on Radiological Controls, Emergency Response, Emergency Classification, Accident Assessment Protective Response, Re-entry/Recovery, and Emergency Operations Facility. The Emergency Plan also stated that EC training would include a comprehensive review of the Emergency Plan and Implementing Instructions, with special attention to the areas of dose projections, protective action recommendations, and communications.

In Revision 6 to the Emergency Plan, dated August 21, 1986, the licensee removed the Table 8-1 Training Matrix from the Emergency Plan, and placed it in Procedure EPI-C3, "Emergency Preparedness Training," Revision 0, effective September 4, 1986. This Emergency Plan revision stated the following:

- Re-training would be conducted annually by job function and in accordance with the Onsite Emergency Plan Training Matrix contained in Attachment 1 to EPI-C3.

- EC training would include the same comprehensive training as in Revision 5 of the Emergency Plan, including classroom training, and drill and exercise performance.

Procedure EPI-C3, Revision 0, specified the following:

- Section 6.2.1: The requalification program shall be conducted on an ERO position basis per Attachment 1 (i.e., the former Table 8-1 training matrix).

- Section 6.2.3: Based on the judgment of the EPU Supervisor and Perry Training Section, a mini-drill or exercise, separate from the annual graded exercise, may be utilized to meet any specified or all requalification requirements.

The second item was a procedural initiative and was not included in Revision 6 to the Emergency Plan. This change which allowed drill and/or exercise participation to meet requalification requirements was a reduction in training commitments, and therefore a potential decrease in effectiveness (DIE) of the Emergency Plan. It also contradicted the statement that requalification would be in accordance with the courses listed in Attachment 1 to EPI-C3. However, this change was later approved in Emergency Plan, Revision 11 in 1994 as noted below.

The requalification training commitment change was incorporated in the Emergency Plan in August, 1994, through Temporary Change Notice 7 to Emergency Plan, Revision 11, such that ERO personnel could meet annual continuing training requirements through participation in a drill or exercise only, to the exclusion of the specialized classroom training. Revision 11 added the following paragraph:

“When practical, participation in drills and exercises can be used to meet the requalification requirements of TMP-2302 (new training program procedure) and to provide hands on experience to ERO personnel.”

The inspectors questioned the meaning and intent of "when practical" relative to the substitution of a drill or exercise for formal classroom training. Formerly, in EPI-C3, the EPU Supervisor and Perry Training Section personnel, exercised judgment as to whether a drill or exercise could be utilized to meet any specified or all requalification requirements. The requalification requirements were specified in Attachment 1 to EPI-C3. This implied that use of a drill or exercise in lieu of classroom training may be considered "practical" if all Attachment 1 training requirements were accomplished during the drill.

Additionally, the present Emergency Plan, Revision 22, contained the following specific requalification training requirements:

- Personnel assigned to the ERO with specific duties and responsibilities receive specialized training for their respective assignments. This training ensures that emergency response personnel maintain and improve their skills.

- EC training will include a comprehensive review of the Emergency Plan and Implementing Instructions, which includes emergency classifications, protective action recommendations, and communications. Other topics to be included in this training are a basic review of: Local County Emergency Plans, the State of Ohio Emergency Plan, the NRC Incident Response Plan, and the interfaces of the Perry Plant Emergency Plan with each.

The inspectors noted that performance in an annual drill or exercise may not provide the specialized training necessary to maintain and improve all necessary responder skills. Additionally, a drill or exercise may not provide ECs with the specialized training they require, including a comprehensive review of the Emergency Plan and Implementing Instructions, to include emergency classifications, protective action recommendations, and communications. For example, the EC may have occasion to perform only one event classification and one protective action recommendation during a drill or exercise, which may not be adequate to satisfy the comprehensive specialized training stated above.

As a result, this issue is an URI (**URI 05000440/2005003-03**) pending NRC review of the following items:

- Verification that any changes to the training matrix received an adequate review in accordance with 10 CFR 50.54(q) to ensure that there have been no DIE of the Emergency Plan.

- Verification that in instances where a drill or exercise was substituted for requalification training, that there was reasonable assurance that those events met all requirements of the training matrix, as well as the additional stringent training requirements specified in the Emergency Plan.

- A review of documentation which demonstrates that Emergency Preparedness and/or Training management reviewed and approved the substitution of a drill or exercise for requalification training only after having verified that the substitution was “practical”.

ERO Interview Results

The team conducted one-on-one interviews with two SMs, two TSC OMs, and two ECs to assess the adequacy of ERO training in the area of event classification. The team asked each manager several questions and presented two scenarios, one General Emergency and one SAE, for the managers to classify in accordance with the licensee’s EAL scheme. The interviewees had access to all the necessary procedures needed to answer the questions and classify the two events.

The interview results were as follows: One SM classified the SAE event as an Alert; one OM classified the General Emergency as an SAE; and one EC classified the General Emergency as an SAE; the other EC classified the SAE as an Alert. Therefore, out of the 12 event classifications (2 for each manager), 4 were inappropriately under-classified.

The licensee performed a detailed analysis of the interview results. Actions included detailed debriefs with all managers interviewed and remediation for those managers who did not respond with the expected scenario classification. Additionally, the scenarios were provided to all SMs, OMs, and ECs, and the results were collectively reviewed for further corrective action.

The team concluded that based upon the licensee's corrective actions and the fact that the scenarios were not sufficiently detailed to limit some incorrect assumptions by the interviewees, there was no safety concern with the ability of ERO managers to properly classify events. However, this was one indication that these managers were potentially lacking the specialized training necessary to maintain their classification skills.

ERO Training

The NRC approved the PNPP Emergency Plan, Revision 5, on August 16, 1985. In Section 8.1.2.2, the licensee committed to providing specialized training to the ERO which was delineated in Table 8-1 of the Plan, and consisted of several training modules for each position. For example, ECs received modules on Radiological Controls Training, Emergency Response, Emergency Classification, Accident Assessment Protective Response, Re-entry/Recovery, and Emergency Operations Facility.

3.7.7 Emergency Preparedness Off-Site Interface

a. Inspection Scope

The team evaluated the licensee's interface with off-site state and county agencies. This included a review of documentation of off-site state and county meetings, letters of agreement with off-site organizations, and training drills.

b. Observations and Findings

No deficiencies were identified.

4.0 Perry PII Review

4.1 Background

By letter dated September 30, 2004, FirstEnergy advised the NRC that prior to receiving the NRC's August 12, 2004, Assessment Followup Letter in which the PNPP was identified to have transitioned into the Multiple/Repetitive Degraded Cornerstone column of the NRC's Action Matrix, actions were underway to improve plant performance. To facilitate these performance improvements, FirstEnergy developed the Perry PII. This improvement initiative was formed using insights from NRC Inspection Procedure 95003, lessons learned from the Davis-Besse Nuclear Power Station, and lessons learned from other stations that were placed under the IP 95003 inspection process. As detailed in the licensee's September 30, 2004, letter, to correct the identified declining trends in performance at Perry, the PII was structured around the following six key improvement initiatives:

- Equipment Performance and Configuration;
- Program/Procedure Review;

- Containment and Safety Systems;
- Corrective Action Implementation Improvement;
- Organizational Effectiveness Improvement; and
- Validations of Root Cause Actions and Effectiveness Review of Root Cause Corrective Actions

To direct the implementation of the PII, a Detailed Action & Monitoring Plan was developed by the FirstEnergy Executive Leadership Team.

As part of this IP 95003 inspection, the team conducted a detailed review of the Perry PII. This review consisted of two parts. The first part of the inspection consisted of a review of the scope of the PII and determined whether the PII, if implemented as written, could achieve the overall goal of correcting the declining trends of performance at Perry. The second part of the review consisted of an inspection of selected actions prescribed in the PII Detailed Action & Monitoring Plan. These reviews were completed and the results are documented in Attachment 2.

5.0 Root and Contributing Cause Assessment

In accordance with Section 2.07 of Inspection Procedure 95003, the team grouped the safety performance deficiencies identified during the inspection by apparent root causes and contributing causes to provide insight into the causes of the performance issues at the facility. It should be noted that this effort was not intended to be a substitute for a more focused root cause study or self-assessment by the licensee.

The team identified the following specific causes:

- A lack of rigor in the evaluation of problems was a major contributor to the ineffective corrective actions identified. For example, when problems were identified, a lack of technical rigor in the evaluation of those problems, at times resulted in an incorrect conclusion which in turn affected the ability to establish appropriate corrective actions. A lack of rigor in the review of performance issues also frequently resulted in the identification of corrective actions that failed to prevent the recurrence of those issues.

- There appeared to be, at times, a lack of a questioning attitude. In the engineering area, this was expressed as a lack of a questioning attitude to off-normal conditions. In other areas, such as operations and maintenance, information was available to personnel which could have, if fully considered, prevented procedure adherence issues as well as other issues that occurred.

- Inconsistent management application and reinforcement of existing standards with respect to staff performance, particularly in the areas of procedure adherence and in the implementation of the CAP contributed to the problems identified during the inspection. The presence of supervisors with the necessary standards to foster good behaviors could have acted as a significant barrier to prevent many of the problems which occurred.

6.0 Management Meetings

Exit Meeting Summary

The team presented the preliminary results of the inspection to Messrs. L. Myers, R. Anderson, F. von Ahn, and other members of licensee management on May 6, 2005. The licensee acknowledged the findings presented. No information reviewed during the inspection and likely to be included in the inspection report was identified as proprietary.

On May 26, 2005, a public exit meeting was held at the Quail Hollow Resort in Painesville, Ohio with Messrs. R. Anderson, F. von Ahn, and other members of licensee management to discuss the results of the inspection. The licensee acknowledged the findings presented. A summary of the meeting, a list of the principal NRC and FirstEnergy attendees, and copies of the overhead slides used at the meeting were issued in a letter dated June 3, 2005 (ML 051540172).

7.0 Licensee-Identified Violations

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

7.1 Procedure Adherence Issues Identified During ESW Pump Re-Assembly

Appendix B of 10 CFR 50, Criterion V, “Instructions, Procedures, and Drawings,” requires that activities affecting quality be prescribed by instructions, procedures, and drawings appropriate to the circumstances and be accomplished in accordance with those instructions, procedures, and drawings. Contrary to the above, on March 21, 2005, maintenance technicians re-assembling the 'A' ESW pump failed to follow the procedural instructions specified in GMI-039, “Disassembly/Reassembly of the Division I and II Emergency Service Water Pumps,” Steps 21.c and Attachment 2 step 2.0 which required the pump shaft set screws to be lubricated and torqued to a required value by following a specified sequence. A QA auditor noted that the maintenance technician, who was being observed by his maintenance supervisor, was not lubricating the set screws and was not torquing the set screws using the specified sequence contained in the procedure. This issue was entered into the licensee’s CAP as CR 05-02586. The issue was of very low safety significance since the problem was identified and corrected prior to the completion of pump re-assembly.

7.2 EAL Decrease in Effectiveness - Notice of Unusual Event Level

Nuclear power reactor licensees may make changes to their emergency plans in accordance with 10 CFR 50.54(q) without prior Commission approval only if the changes do not decrease the effectiveness of the plans and the plans, as revised, continue to meet the standards of 50.47(b) and the requirements of Appendix E. Emergency Action Levels that are to be used for determining when and what type of protective measures should be considered in an emergency are an integral part of the emergency plan. Contrary to the above, EALs KU2, "Significant degradation of offsite communications capabilities," and MU1, "Release of toxic OR flammable gases affecting the Protected Area boundary deemed detrimental to the safe operation of the plant," were revised on June 15, 1998 without prior NRC approval although these EAL revisions decreased the effectiveness of the Emergency Plan. As part of the licensee's immediate corrective actions, licensee personnel restored EALs KU2 and MU1 to their original NRC-approved wording. The licensee entered this issue into their CAP as CR 04-01244. Although these EALs were in a degraded condition for about 6 years, because there were no emergencies declared using the inappropriately worded EALs during this time, the issue was of very low safety significance.

7.3 EAL Decrease in Effectiveness - Alert Level

Nuclear power reactor licensees may make changes to their emergency plans in accordance with 10 CFR 50.54(q) without prior Commission approval only if the changes do not decrease the effectiveness of the plans and the plans, as revised, continue to meet the standards of 50.47(b) and the requirements of Appendix E. Emergency Action Levels that are to be used for determining when and what type of protective measures should be considered in an emergency are an integral part of the emergency plan. Contrary to the above, EAL GA2, "Major damage to irradiated fuel," was revised on March 16, 1998 without prior NRC approval although this EAL revision decreased the effectiveness of the Emergency Plan. As part of the licensee's immediate corrective actions, licensee personnel restored EAL GA2 to its original NRC-approved wording. The licensee entered this issue into their CAP as CR 04-04827. Although this EAL was in a degraded condition for about 7 years, because there were no emergencies declared using the inappropriately worded EAL during this time, the issue was of very low safety significance.

7.4 Deletion of the RPS Technician From Table 5-1 of the Emergency Plan

Nuclear power reactor licensees may make changes to their emergency plans in accordance with 10 CFR 50.54(q) without prior Commission approval only if the changes do not decrease the effectiveness of the plans and the plans, as revised, continue to meet the standards of 50.47(b) and the requirements of Appendix E. Table 5-1 to Revision 5 of the Perry Emergency Plan specified two shift response positions for the in-plant protective actions functional area. These were the HP Technician and the RP Section Technician. Contrary to the above, the RP Section Technician position was deleted in Emergency Plan, Revision 13, without prior NRC approval although this Emergency Plan revision decreased the effectiveness of the Emergency Plan. As part of the licensee's immediate corrective actions, an additional HP Technician was assigned on shift 24 hours a day, pending a revision to the Emergency Plan to restore the RP Section Technician position to Table 5-1. This finding was of very low safety significance since Table 5-1 of the Emergency Plan still specified the shift HP Technician for in-plant protective actions.

7.5 Inadequate Procedure With Potential to Drain Suppression Pool

10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires that activities affecting quality be prescribed by instructions, procedures, and drawings appropriate to the circumstances and be accomplished in accordance with those instructions, procedures, and drawings. Contrary to this requirement, on February 28,

2005, during performance of SOI-E12, licensee personnel identified that continuing with the procedure as written would result in the unplanned draining of the suppression pool to the auxiliary building drain sump. This issue was entered into the licensee's corrective action program as CR 05-01596. The issue was of very low safety significance since the procedure error was identified prior to the completion of the procedure.

ATTACHMENT 1: LIST OF FINDINGS
ATTACHMENT 2: PERRY PERFORMANCE IMPROVEMENT INITIATIVE REVIEW
ATTACHMENT 3: SUPPLEMENTAL INFORMATION

ATTACHMENT 1

FINDINGS IDENTIFIED DURING THE IP 95003 INSPECTION

The following findings were identified during the IP 95003 inspection activities and are referenced in applicable sections of the inspection report. The findings are grouped in accordance with the performance area which was most directly affected by the finding (e.g. corrective action, procedure adherence, design, etc.).

1.0 Findings Associated With the Identification and Implementation of Corrective Actions

1.1 Failure to Adequately Address SLC Relief Valve Test Failures

Introduction: A finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action,” was NRC-identified when licensee personnel failed to prevent repetition of a CAQ. Specifically, the SLC system pump discharge pressure relief valves failed to satisfy ASME acceptance criteria for 6 of 10 in-service tests (ISTs) conducted over the last 20 years. On two occasions, in 1989 and 2001, the as-found relief valve condition would have prevented the SLC system from being able to perform its intended design function to mitigate an ATWS event, coincident with a MSIV closure.

Description: During a review of CR 04-06235 and CR 04-06591 that were initiated during the SLC SHR, the team identified that the SLC pump discharge pressure relief valves had a repetitive failure history. During ASME IST relief valve testing conducted every 24 months, the as-found relief valve setpoints were routinely found outside of the IST acceptance criteria.

The team determined that licensee personnel had multiple opportunities to identify this adverse trend. Although a CR was initiated for each test failure, a test failure was typically categorized as a CAQ to only be specifically addressed with no further evaluation. Additional opportunities to identify this issue included:

- CR 01-3071 reviewed NRC Information Notice 2001-13, "Inadequate SLC System Relief Valve Margin." Corrective actions following the licensee’s review of CR 01-3071 focused only on relief valve setpoint design margin.
- In March 2003, licensee personnel performed calculation EA-0241, "ASME Class 2 and 3 Relief Valve Expanded Set Pressure Testing Acceptance Criteria." As a result, the SLC relief valve IST acceptance criteria was expanded from 1358 pounds per square inch gauge (psig) to 1442 psig (1400 +/- 3 percent); to 1302 psig to 1540 psig (1400 +10/-7 percent). The purpose of the expanded acceptance criteria was to reduce the number of as-found test failures.
- CR 04-6235 regarding the licensee’s PII SHR, re-reviewed IN 2001-13.
- CR 04-6591 regarding the licensee’s PII SHRs identified an excessive relief valve setpoint tolerance, since relief valve blowdown margin had not been considered and included.

- CR 05-0713 identified inconsistencies between SLC relief valve calculations and the plant design basis.

The team also identified inconsistencies between the ATWS design analysis, performed for the 1999 Perry Power Uprate, and the SLC relief valve setpoint calculations. The design analysis assumed a maximum reactor pressure during an ATWS-MSIV closure event of about 1150 psig, although a reactor pressure of 1113 psig was used in the design calculations for relief valve setpoint determination. In addition, the team noted that several historical as-found values were lower than the calculated SLC pump discharge pressure during an ATWS event, considering piping head loss and SLC positive displacement pump pressure pulsations. Specifically, in 1989, SLC relief valve C41-F029B was found at 1260 psig, and in 2001, SLC relief valve C41-F029A was found at 1228 psig.

Licensee personnel subsequently determined that on these two prior occasions, the as-found condition of a SLC relief valve would have prevented the system from performing its intended ATWS design function.

Analysis: The team determined that the failure of licensee personnel to adequately address SLC relief valves failures was a performance deficiency which warranted a significance evaluation. Specifically, the SLC pump discharge pressure relief valves repetitively failed to satisfy the as-found IST acceptance criteria. Licensee personnel subsequently determined that on two occasions the as-found condition would have prevented the SLC system from being able to perform its intended design function to mitigate an ATWS-MSIV closure event. The Mitigating Systems cornerstone was impacted by this issue. The team reviewed the samples of minor issues in IMC 0612, “Power Reactor Inspection Report,” Appendix E, “Examples of Minor Issues,” and determined that Example 2.a was similar to this issue and identified this issue as more than minor. Also, in accordance with Appendix B, “Issue Screening,” of IMC 0612, the team determined that the finding was of more than minor significance since the finding was associated with the equipment performance attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

Using IMC 0609, “Significance Determination Process,” Appendix A, “User Guide for Determining the Significance of Reactor Inspection Findings for At-Power Situations,” and “SDP Phase 1 Screening Worksheet for Initiating Events, Mitigating Systems, and Barriers Cornerstones,” the team determined that because this finding represented an actual loss of safety function of a system, a Phase 2 SDP analysis was required. In the Phase 2 SDP assessment, the ATWS event worksheet was reviewed as specified by the Perry Plant Risk-Informed Inspection Notebook. The dominant core damage sequence was an ATWS event, followed by a loss of the SLC system. The Phase 2 SDP assessment determined that this finding was of very low safety significance (Green) because one of two SLC pumps remained available.

The team also concluded that this finding affected the cross-cutting area of Problem Identification and Resolution since licensee personnel did not adequately evaluate prior SLC relief valve as-found test failures, and inappropriately revised the tolerance margins of the relief valves in a non-conservative direction.

Enforcement: Appendix B of 10 CFR 50, Criterion XVI, “Corrective Action,” requires, in part, that measures shall be established to ensure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. Contrary to this requirement, the licensee failed to take corrective actions and did not determine the cause or preclude repetition of a CAQ. Specifically, licensee personnel performed an ASME IST of the SLC pump discharge pressure relief valves C41-F029A and C41-F029B every 24 months. The team identified that the as-found relief valve setpoints were outside of the nominal ASME tolerance of +/- 3 percent, for 6 of the 10 IST tests conducted during the last 20 years. The licensee subsequently determined that on two occasions, in 1989 and 2001, the as-found conditions indicated that the SLC system would not have been able to perform its intended design function to mitigate an ATWS event, coincident with an MSIV closure.

However, because of the very low safety significance of the issue and because the issue has been entered into the licensee’s CAP, the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (**NCV 05000440/2005003-04**). This issue was entered into the licensee’s CAP as CR 05-03827.

As part of the licensee’s immediate corrective actions, licensee personnel compared the as-left setpoints for the currently installed relief valves to a design setpoint value, based on an appropriate maximum reactor pressure, and ensured that an adequate margin existed for the SLC relief valves to adequately perform their safety function.

1.2 Permanent Structures in Contact With Containment Wall

Introduction: A finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action,” was NRC-identified when licensee personnel failed to identify and correct numerous permanent structures that did not meet the required seismic separation distance to the inside containment liner wall.

Description: On March 30, 2005, during a plant tour while the plant was shutdown for refueling, the team identified that numerous permanent structures such as floor grating, metal ladders supports, and grating support brackets came in direct contact with the containment wall or did not meet the required 1-inch separation distance to the containment wall per structural drawing D-511-062, “Reactor Building Steel Framing," Revision H. The inadequate structural clearance increased the likelihood that the safety-related containment wall would be damaged during a seismic event.

Engineering personnel initiated CR 05-02905 to evaluate the deficiencies identified by the team and performed several walkdowns of the containment building. The engineering walkdowns identified over 600 clearance deficiencies between permanently installed structures and the containment wall. In addition, engineering calculation 3:41.055 was performed to redefine and establish new clearance requirements based on specific containment building elevations.

Subsequently, on May 4, 2005, following the implementation of corrective actions to address this issue including an extent of condition review, the team conducted additional containment walkdowns and identified two additional examples in which clearance requirements between structures and the containment liner were not met. Licensee personnel confirmed the observation, conducted additional reviews, and identified 12 additional examples where clearance requirements were not met, necessitating additional efforts to correct these conditions prior to unit restart. CRs 05-04088, and 05-04097 were initiated to address these new issues.

Engineering evaluations documented under CRs 05-02905 and 05-04097 determined that the identified clearance deficiencies would not have affected the operability of the containment vessel or the steel platforms and concrete structures inside containment during a postulated seismic event or accident conditions.

Analysis: The team determined that the failure to identify and implement effective corrective actions to address numerous permanent structures that were not properly installed in accordance with the applicable structural drawing was a performance deficiency which warranted a significance evaluation. The Barrier Integrity cornerstone was impacted by this issue. The team reviewed the samples of minor issues in IMC 0612, "Power Reactor Inspection Report," Appendix E, "Examples of Minor Issues," and determined that there were no examples similar to this issue. In accordance with Appendix B, "Issue Screening," of IMC 0612, the team determined that the finding was of more than minor significance since the finding was associated with the configuration control attribute of the Barrier Integrity cornerstone and affected the cornerstone objective of providing reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events.

Using IMC 0609, "Significance Determination Process," Appendix A, "User Guide for Determining the Significance of Reactor Inspection Findings for At-Power Situations," and "SDP Phase 1 Screening Worksheet for Initiating Events, Mitigating Systems, and Barriers Cornerstones," the team determined that this finding 1) did not represent a degradation of the radiological barrier function of the control room, auxiliary building, spent fuel pool, or annulus exhaust gas treatment system; 2) did not represent a degradation of the barrier function of the control room against smoke or toxic gas; 3) did not represent an actual open pathway in the physical integrity of the containment; and 4) did not involve an actual reduction in the defense-in-depth for the atmospheric pressure control or the hydrogen control functions of containment. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

The team also concluded that this finding affected the cross-cutting area of Problem Identification and Resolution because licensee personnel missed an opportunity to correct the condition which had occurred previously.

Enforcement: Appendix B of 10 CFR 50, Criterion XVI, "Corrective Action," requires, in part, that measures shall be established to ensure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. Contrary to this requirement, the licensee failed to identify and correct numerous permanently installed structures located inside containment that did not meet the required 1-inch separation distance to the containment wall per structural drawing D-511-062, “Reactor Building Steel Framing," Revision H. In addition, on May 4, 2005, during a subsequent walkdown to assess corrective actions for this issue, the team identified that the extent of condition reviews and applicable corrective actions had not been fully effective in correcting all of the clearance deficiencies.

However, because of the very low safety significance of the issue and because the issue has been entered into the licensee’s CAP, the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy **(NCV 05000440/2005003-05)**. This issue was entered into the licensee’s CAP as CRs 05-02905, 05-04088, and 05-04097.

Corrective actions to address this issue included several complete walkdowns of the containment building, performing a past operability review, performing calculations to establish redefined clearance requirements, and correcting over 600 clearance deficiencies between permanent structures and the containment wall.

1.3 Drywell Supply Fan Trips Due to Inadequate Maintenance

Introduction: A finding (FIN) of very low safety significance (Green) was self-revealed when repetitive drywell supply fan failures occurred due to inadequate maintenance and inadequate corrective actions to address a previous failure due to an identical root cause.

Description: On February 22, 2005, while starting a drywell supply fan in the containment vessel and drywell purge (CVDWP) system to support entry into the drywell, the fan thermal overload actuated, tripping the fan. Investigation by licensee personnel revealed that following recent maintenance activities, two previously missing bolts had been replaced with bolts of a longer dimension than that which was specified in the fan design documents. As a result, the longer bolts protruded far enough into the fan housing that the fan blades contacted the bolts and the fan tripped on thermal overload. Following the maintenance, licensee personnel failed to perform an adequate post-maintenance test sufficient to detect that the fan no longer rotated freely. A similar event was documented in CR 99-0718. For this event, corrective actions included updates to the drawings to identify the proper bolt size. However, this corrective action proved ineffective at preventing recurrence.

Identical fans existed in both the CVDWP system and the drywell cooling (DWC) system. The CVDWP system was designed to reduce airborne contaminants within the drywell and containment such that personnel could work in the area without respiratory protection. The DWC system was designed to provide cooling to areas within the drywell so that those areas remained suitable for equipment operation. During emergency conditions that lead to elevated drywell temperatures, the DWC system was also designed to provide cooling to prolong the operation of equipment in the drywell.

Analysis: The team determined that the failure to install appropriate bolts in the CVDWP system was a performance deficiency which warranted a significance evaluation. The Mitigating Systems cornerstone was impacted by this issue. The team reviewed the samples of minor issues in IMC 0612, “Power Reactor Inspection Report,” Appendix E, “Examples of Minor Issues,” and determined that there were no examples similar to this issue. In accordance with Appendix B, “Issue Screening,” of IMC 0612, the team determined that the finding was of more than minor significance since the finding could reasonably be viewed as a precursor to a more significant event. In particular, identical fans exist in other plant systems and failure of those fans, under other circumstances, could be more significant. Specifically, the DWC ventilation system was designed to provide cooling to safety systems in normal and accident conditions.

Using IMC 0609, “Significance Determination Process,” Appendix A, “User Guide for Determining the Significance of Reactor Inspection Findings for At-Power Situations,” and “SDP Phase 1 Screening Worksheet for Initiating Events, Mitigating Systems, and Barriers Cornerstones,” the team determined that this finding 1) was not a design deficiency or qualification deficiency; 2) did not represent an actual loss of safety function of a system; 3) did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time; 4) did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant; and 5) did not screen as potentially risk significant due to seismic, flooding, or a severe weather initiating event. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

The team also concluded that this finding **(FIN 05000440/2005003-06)** also affected the cross-cutting area of Problem Identification and Resolution since licensee personnel failed to prevent the recurrent use of improper bolts.

Enforcement: Because the CVDWP system was not subject to the requirements of 10 CFR 50, Appendix B, no violation of regulatory requirements occurred. This issue was entered into the licensee’s CAP as CR 05-01319.

1.4 Failure to Adequately Address LPCS/RHR 'A' Waterleg Pump Air-Binding Concern

Introduction: A finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action,” was NRC-identified when licensee personnel failed to promptly identify a CAQ. Specifically, corrective actions following air-binding of the LPCS/RHR 'A' waterleg pump failed to identify that additional air voids existed in ECCS piping.

Description: As discussed in IR 05000440/2003010, on August 14, 2003, following a LOOP, the waterleg pump serving both the LPCS system and 'A' RHR sub-system became air-bound due to accumulated air in a portion of the line that had not been vented due to a high point vent valve that was inadvertently omitted from the system venting procedure. As part of the corrective actions associated with CR 03-04764, the licensee performed an extent of condition review to identify other high point vents that had been omitted from system venting procedures. Additional venting points were identified and the corrective action was closed. Subsequently, on September 22, 2004, the licensee performed a review of OE 18987 relating to a low suction pressure trip of the RCIC system at another facility. The OE addressed abandoned-in-place RHR piping used for the Steam Condensing mode of RHR. At the interface between the RHR and RCIC systems, air voids developed which air-bound the pump during a test of the high pressure coolant injection system. Licensee personnel determined that a similar configuration existed at Perry and that the vent valve for the piping section, E12F0569, was not included in the system venting procedures that had been previously reviewed. When licensee personnel vented the abandoned section, air was removed from the piping.

The team reviewed the cause analysis for CR 04-04917 and noted that the licensee determined that a thorough review of RHR suction piping was not needed because Problem Identification Form (PIF) 96-0212 had performed that review. However, the corrective actions for that PIF failed to identify the omitted high point vent valve associated with NOV 05000440/2003010-03. Therefore, the team concluded that the reliance on a corrective action completed in the mid 1990s that already had proven ineffective at detecting vent problems on RHR suction piping did not provide assurance that other vents points had been omitted from licensee procedures.

Analysis: The team determined that the failure to identify and evaluate all high point vents in the ECCS systems was a performance deficiency which warranted a significance evaluation. The Mitigating Systems cornerstone was impacted by this issue. The team reviewed the samples of minor issues in IMC)0612, “Power Reactor Inspection Report,” Appendix E, “Examples of Minor Issues,” and determined that there were no examples similar to this issue. In accordance with Appendix B, “Issue Screening,” of IMC 0612, the team determined that the finding was of more than minor significance since the finding was associated with the equipment performance attribute of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, air that had accumulated in abandoned steam condensing piping, as demonstrated at another facility and discussed in operating experience information available to the licensee, had the potential to render the RCIC system inoperable.

Using IMC 0609, “Significance Determination Process,” Appendix A, “User Guide for Determining the Significance of Reactor Inspection Findings for At-Power Situations,” and “SDP Phase 1 Screening Worksheet for Initiating Events, Mitigating Systems, and Barriers Cornerstones,” the team determined that this finding 1) was not a design deficiency or qualification deficiency; 2) did not represent an actual loss of safety function of a system; 3) did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time; 4) did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant; and 5) did not screen as potentially risk significant due to seismic, flooding, or a severe weather initiating event. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

The team also concluded that this finding affected the cross-cutting area of Problem Identification and Resolution because licensee personnel failed to perform an adequate extent of condition review for omitted high point vent valves.

Enforcement: Appendix B of 10 CFR 50, Criterion XVI, “Corrective Action,” requires, in part, that measures shall be established to ensure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. Contrary to this requirement, the licensee failed to adequately determine the extent of condition for omitted vent valves in ECCS systems. Specifically, the licensee failed to identify that 1E12F0569, which vented a high point in the RCIC system, was omitted from licensee venting procedures until September 22, 2004, when prompted by review of Operating Experience from another facility.

However, because of the very low safety significance of the issue and because the issue has been entered into the licensee’s CAP, the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (**NCV 05000440/2005003-07**). This issue was entered into the licensee’s CAP as CR 05-04017.

As part of the licensee’s immediate corrective actions, high point vent 1E12F0569 was added to the licensee’s venting procedures and the high point was verified to be properly vented.

1.5 Failure to Adequately Address MOV Stem Lubrication Concerns

Introduction: A finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action,” was NRC-identified when licensee personnel failed to correct a CAQ in a timely manner. Specifically, in the early 1990s, industry operating experience identified that “Never-Seez” was not an adequate MOV stem lubricant since its use could result in increased friction and wear. In 2005, the licensee continued to use “Never-Seez” in safety-related MOVs.

Description: In the early 1990s, industry operating experience identified that “Never-Seez,” when used as an MOV stem lubricant, resulted in increased stem friction and accelerated wear of the stem nut. Issues with the use of “Never-Seez” as a stem lubricant were documented in NUMAC lube notes in 1990 and 1991, and EPRI Technical Report, "MOV Performance Prediction Program - Stem/Stem-Nut Lubrication Test Report," dated August 1993. The EPRI report identified significant variability in stem friction as a direct result of “Never-Seez” usage. Because stem friction directly affects the ability of an MOV to re-position, large frictional increases can adversely affect MOV operability and functionality. The EPRI report also stated that several other lubricants demonstrated superior performance by reducing stem nut wear and friction variability.

In 1994, CR 94-0905 evaluated variations in MOV stem thrust, due to the use of “Never-Seez.” CR 96-0462 evaluated similar MOV issues, and resulted in a corrective action to replace “Never-Seez” with a different lubricant. However, licensee personnel determined that the lubricant change-out activities could be performed on a case-by-case basis, based on MOV test performance data. In 2000 and 2001, additional MOV stem lubricant issues were identified in CRs 2000-2358, 2464, 2538, 2001-0018, 0827, 0923, 1260, and 3648. In follow-up to CR 2001-0018, licensee personnel determined that the use of “Never-Seez”, as an MOV stem lubricant, resulted in degraded MOV performance. CRs for multiple valve issues documented significant margin reductions in valve operator thrust and severe stem nut wear. Degraded MOV performance, as a result of continued “Never-Seez” usage, included:

- In 1996, a LPCS test valve to the suppression pool was unable to close under high flow rates, coincident with degraded voltage conditions;

- In 2000, a RCIC test return valve to the CST failed to satisfy test acceptance criteria; and

- In 2001, the 'A' RHR pump minimum flow valve failed to satisfy test acceptance criteria.

Although the licensee had identified an adverse trend in MOV performance, the corrective actions from CR 2001-1700, "Collective Significance for MOV Stem Lubrication Issues," scheduled stem lubricant change-out over a 4 year period. The original lubricant change-out schedule included 65 safety-related MOVs for RFO10, but the outage work scope was later reduced to only 30 MOVs. Subsequently, CR 03-3047 re-evaluated the corrective action schedule and extended the schedule to an 8 year period. As of January 2005, 26 safety-related MOVs and 28 nonsafety-related MOVs, designated as system critical, still had “Never-Seez” in use as a stem lubricant.

Analysis: The team determined that the failure to resolve an identified CAQ in timely manner regarding the use of “Never-Seez” lubricant in MOV applications was a performance deficiency which warranted a significance evaluation. The Mitigating Systems cornerstone was impacted by this issue. The team reviewed the samples of minor issues in IMC 0612, “Power Reactor Inspection Report,” Appendix E, “Examples of Minor Issues,” and determined that there were no examples similar to this issue. In accordance with Appendix B, “Issue Screening,” of IMC 0612, the team determined that the finding was of more than minor significance since the finding was associated with the equipment performance attribute of the Mitigating Systems cornerstone and affected the cornerstone objected of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, over a 10 year period, licensee personnel deferred MOV stem lubricant replacement while multiple MOVs failed as-found test acceptance criteria and exhibited severe stem nut wear, with the use of “Never-Seez” as the root cause.

Using IMC 0609, “Significance Determination Process,” Appendix A, “User Guide for Determining the Significance of Reactor Inspection Findings for At-Power Situations,” and “SDP Phase 1 Screening Worksheet for Initiating Events, Mitigating Systems, and Barriers Cornerstones,” the team determined that this finding 1) was not a design deficiency or qualification deficiency; 2) did not represent an actual loss of safety function of a system; 3) did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time; 4) did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant; and 5) did not screen as potentially risk significant due to seismic, flooding, or a severe weather initiating event. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

The team also concluded that this finding affected the cross-cutting area of Problem Identification and Resolution because licensee personnel failed to resolve a known CAQ in a timely manner.

Enforcement: Appendix B of 10 CFR 50, Criterion XVI, “Corrective Action,” requires, in part, that measures shall be established to ensure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. Contrary to this requirement, licensee personnel failed to implement prompt corrective actions to replace “Never-Seez” with an appropriate stem lubricant on safety-related MOVs. Specifically, since 1991, multiple industry operating experience identified that the use of “Never-Seez”, as an MOV stem lubricant, was not appropriate, and the licensee experienced multiple MOV as-found test failures and severe stem nut wear, attributed to the use of “Never-Seez”. As of January 2005, the licensee still had “Never-Seez” in use, as a stem lubricant, in safety-related MOV applications.

However, because of the very low safety significance of the issue and because the issue has been entered into the licensee’s CAP, the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (**NCV 05000440/2005003-08**). This issue was entered into the licensee’s CAP as CR 05-01383.

As part of the licensee’s immediate corrective actions, all affected valves were scheduled to have their stem lubrication changed by the end of RFO10.

1.6 Failure to Comply With ARC Process During EDG Modifications

Introduction: A finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” was NRC-identified when licensee personnel failed to adhere to the ARC procedure used for the modification of safety-related equipment without a completed and approved modification package.

Description: On March 30, 2005, licensee personnel initiated a CR questioning the use of the ARC process to install insulation on the missile shield around the Division 1 EDG while the missile shield remained in service. Licensee management reviewed the CR as well as the procedure governing ARCs, NOP-CC-2003, “Engineering Changes,” and concluded that the procedure was followed. The team reviewed the same documents and concluded that by the licensee’s procedure, ARCs could not be used to modify in service structures. NOP-CC-2003 stated, “ARCs shall only be used to alter or modify SSCs that are out of service and physically isolated (i.e. clearance posted) from electrical and mechanical sources. ARCs shall not be used to modify any portion of an in service or operable (i.e. energized, pressurized) SSC.” NOP-CC-2003 also stated, “Once an ARC is issued and field implementation has commenced, the system shall be considered ‘out of service’ and shall not be energized, operated, tested (other than continuity, manual rotation or similar non-energized/filled/loaded conditions), or considered ‘available’ until the formal Engineering Change Package or Revision Notice is issued for implementation.”

The team discussed the issue with members of licensee management to ensure a common understanding of the procedural requirements. Licensee management stated that the procedural requirement did not apply to structural modifications and since the modification only affected the missile shield structure, was not required to be considered as out of service and inoperable. Licensee management also stated they had conferred with corporate management as well as the procedure authors who concurred with their position that ARCs could be implemented on in service structures. The team noted that an SSC represented a *structure* (emphasis added), system, or component. The team then raised the issue to more senior members of licensee management who concurred with the team that procedurally, the missile shield could not be considered operable until the engineering package was approved and issued.

Analysis: The team determined that the failure to adhere to the At-Risk-Change process during EDG modification activities was a performance deficiency which warranted a significance evaluation. The Mitigating Systems cornerstone was impacted by this issue. The team reviewed the samples of minor issues in IMC 0612, "Power Reactor Inspection Report," Appendix E, "Examples of Minor Issues," and determined that there were no examples similar to this issue. In accordance with Appendix B, "Issue Screening," of IMC 0612, the team determined that the finding was of more than minor significance since the finding was associated with the configuration control attribute of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

Using IMC 0609, "Significance Determination Process," Appendix A, "User Guide for Determining the Significance of Reactor Inspection Findings for At-Power Situations," and "SDP Phase 1 Screening Worksheet for Initiating Events, Mitigating Systems, and Barriers Cornerstones," the team determined that this finding 1) was not a design deficiency or qualification deficiency; 2) did not represent an actual loss of safety function of a system; 3) did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time; 4) did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant; and 5) did not screen as potentially risk significant due to seismic, flooding, or a severe weather initiating event. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

The team also concluded that this finding affected the cross-cutting area of Problem Identification and Resolution because licensee personnel failed to adequately address the issue until questioned by the team.

Enforcement: Appendix B of 10 CFR 50, Criterion V, "Instructions, Procedures and Drawings," requires, in part, that activities affecting quality shall be prescribed by instructions, procedures, and drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, and drawings. The licensee developed NOP-CC-2003, "Engineering Changes," to establish design control. NOP-CC-2003 stated, in part, that "ARCs [At-Risk-Changes] shall only be used to alter or modify SSCs [structures, systems, and components] that are out of service and physically isolated (i.e. clearance posted) from electrical and mechanical sources. ARCs shall not be used to modify any portion of an in service or operable (i.e.

energized, pressurized) SSC." The procedure also stated, "Once an ARC is issued and field implementation has commenced, the system shall be considered 'out of service' and shall not be energized, operated, tested (other than continuity, manual rotation or similar non-energized/filled/loaded conditions), or considered 'available' until the formal Engineering Change Package or Revision Notice is issued for implementation." Contrary to these requirements, during RFO10, the licensee implemented an ARC to the missile shield for the EDGs without declaring the missile shield inoperable or unavailable.

However, because of the very low safety significance of the issue and because the issue has been entered into the licensee's CAP, the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (**NCV 05000440/2005003-09**). This issue was entered into the licensee's CAP as CR 05-01580.

As part of the licensee's immediate corrective actions, all modification work associated with the ARC process was suspended until all cognizant personnel were provided training on this issue. Licensee personnel also subsequently revised the procedure and established a technical basis for the modifications to the missile shield. Licensee analysis of the design and interim configurations confirmed the installation could perform the missile barrier function throughout the construction process.

1.7 <u>Failure to Adequately Address Control Rod Movement Concerns</u>

<u>Introduction</u>: A finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," was NRC-identified when licensee personnel failed to implement adequate corrective actions for root causes associated with a significant condition adverse to quality. Specifically, the licensee identified management failures in identifying problems with reactivity control systems as a root cause for unexpected control rod movement, however licensee corrective actions failed to address this issue.

<u>Description</u>: While performing a reactor startup on August 20, 2003, indications for control rod 02-27 displayed control rod movement from position 02 to position 10 following insertion of a signal to withdrawal the rod a single notch. Prior to the change in position indication, operators had input three single notch withdrawal signals but did not observe a change in indicated rod position. Prior to attempting to withdraw the rod again, the operators, per procedure, increased drive pressure and input another single notch withdrawal signal. After investigating the event, licensee personnel determined that the rod had been withdrawn in single notches with each attempt, but material condition deficiencies with the rod position indicating system had masked the rod withdrawal. The system had multiple deficiencies that resulted in instances where 1 of 2 position channels would fail to indicate rod position at some notches. In order to perform rod withdrawal, licensee personnel substituted data from the properly functioning channel to the non-functioning channel to clear the rod block. By system design, only channel 1 was displayed to the operators. Secondary indications of rod withdrawal such as neutron count were monitored, but since the rod was in a low reactivity region, did not indicate any change. In addition to rod position indication problems, the licensee historically experienced problems with the control rod hydraulic

system. In multiple instances, operators increased control rod drive pressure to cause a control rod to move. Thus, no rod movement was an anticipated system response. The licensee performed a root cause analysis of the event that identified two root causes. The licensee determined the event occurred due to the failure of the operators to use all available indications to determine if the rod had moved. The second cause was management follow-up and monitoring failing to identify problems.

Licensee corrective actions primarily focused on changing operator behavior to verify rod position through the use of multiple rod position indication channels. In addition, improvements to the plant's material condition were addressed as part of other material condition improvement initiatives. With respect to management oversight, the licensee developed a single corrective action narrowly focused on the readiness of reactivity management systems prior to plant start-up. None of the corrective actions associated with the CR addressed the broader issue of management failure to identify problems and to maintain reactivity control systems. The corrective action to address the management issues consisted of a revision to the restart readiness business practice to evaluate reactivity management systems for potential challenges and, where necessary, schedule or establish contingency actions or training. The team noted that as written, the procedure emphasized continued reliance on work arounds for degraded reactivity management systems and did nothing to improve the maintenance of these systems. Further, the licensee implemented the corrective action in a document that did not conform to 10 CFR 50, Appendix B requirements associated with maintaining quality records. The scope of the implementing document only applied to a restart following outages longer than 1 week in length. Thus, the licensee would not need to follow the procedure for an outage of shorter length or for major power changes, even though the licensee had experienced challenges with the Rod Control and Information System and the CRDH system during these evolutions.

Analysis: The team determined that the failure to address management oversight of the reactivity control systems was a performance deficiency which warranted a significance evaluation. The Initiating Events cornerstone was impacted by this issue. The team reviewed the samples of minor issues in IMC 0612, "Power Reactor Inspection Report," Appendix E, "Examples of Minor Issues," and determined that there were no examples similar to this issue. In accordance with Appendix B, "Issue Screening," of IMC 0612, the team determined that the finding was of more than minor significance since it could be reasonably viewed as a precursor to a more significant event.

Although not suited for SDP evaluation, the finding was determined to be of very low safety significance because no initiating event occurred.

This team also concluded that this finding affected the cross-cutting area of Problem Identification and Resolution because licensee personnel failed to adequately resolve a known CAQ.

Enforcement: Appendix B of 10 CFR 50, Criterion XVI, "Corrective Action," requires, in part, that measures shall be established to ensure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. Contrary to this requirement, as of August 20, 2003, licensee personnel failed to implement adequate corrective actions to address management deficiencies associated with unexpected control rod movement. Specifically, although the licensee added a procedural step to their restart readiness business practice, the corrective action did not cover all activities that could result in significant control rod movement.

However, because of the very low safety significance of the issue and because the issue has been entered into the licensee's CAP, the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (**NCV 05000440/2005003-10**). This issue was entered into the licensee's CAP as CR 05-01640.

As part of the licensee's corrective actions, CR 03-05995 was previously generated to address organizational issues through the use of the Plant Health Committee, clarification of the roles and responsibilities of managers and directors, and to develop the Perry PII.

1.8 Failure to Adequately Address Elevated Dose Rate Concerns

Introduction: A finding (FIN) of very low safety significance (Green) was NRC-identified when licensee personnel failed to implement corrective actions to prevent recurrence of a significant CAQ in a timely manner. Specifically, corrective actions to investigate the organizational causes for elevated dose rates in Refueling Outage 9 (RFO9) failed to identify corrective actions to prevent recurrence.

Description: The team reviewed CR 03-03880 initiated on June 13, 2003, as a result of elevated outage dose and dose rates identified in RF09. Licensee personnel initiated CR 03-03880 to investigate chemistry and organizational causes and their effects on elevated dose rates. The investigation focused primarily on the operational chemistry aspects during operating cycle 9 that contributed to elevated dose rates during the refueling outage. Prior to RF09, the licensee made a decision to implement the emerging technology of Noble Metals Chemical Application (NMCA) to the reactor coolant. Although operating experience pertaining to NMCA identified elevated dose rate as a consequence, the organization believed that dose would not be a problem based on various plant component sizing and process differences. However, as a result of not preconditioning the reactor coolant with hydrogen prior to the application of NMCA, the related dose rates resulted in significantly increased outage dose during RF09. The root cause identified that poor change management resulted in the elevated accumulated dose experienced during the outage. The root cause inappropriately justified not identifying any preventative actions for poor change management because the licensee had made a business decision to implement this developing technology. The team noted that better change management techniques could have resulted in recognition of the adverse consequences of the new technology and the licensee could then have responded to address those consequences.

Analysis: The team determined that the failure to identify preventative and corrective actions for decision-making that involved change management and emerging technology was a performance deficiency which warranted a significance evaluation. The radiation protection cornerstone was impacted by this issue. The team reviewed the samples of minor issues in IMC 0612, "Power Reactor Inspection Report,"

Appendix E, “Examples of Minor Issues,” and determined that there were no examples similar to this issue. In accordance with Appendix B, “Issue Screening,” of IMC 0612, the team determined that the finding was of more than minor significance because, if left uncorrected, the finding would become a more significant safety concern.

Although not suited for SDP evaluation, the finding was determined to be of very low safety significance because no safety-related equipment has been rendered inoperable due to the lack of a corrective action.

The team also concluded that this finding **(FIN 05000440/2005003-11)** affected the cross-cutting area of Problem Identification and Resolution because the licensee failed to implement a corrective action for a root cause of a significant CAQ.

Enforcement: Because the issues identified were related to RP controls and were not subject to the requirements of 10 CFR 50, Appendix B, no violation of regulatory requirements occurred. This issue was entered into the licensee’s CAP as CR 05-1245.

1.9 Failure to Adequately Address Division 2 EDG Oil Leak Concern

Introduction: A finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action,” was NRC-identified when licensee personnel failed to correct a CAQ in a timely manner. Specifically, the licensee did not repair a long-standing minor Division 2 EDG lubricating oil cooler packing leak that was identified in November 2000 until May 2004 when the leak degraded and required emergent maintenance, rendering the EDG unavailable.

Description: On November 14, 2000, a minor oil leak was identified by maintenance technicians from the Division 2 EDG lubricating oil cooler lantern packing ring flange connection. The leak occurred at a new packing ring that was installed after the old packing ring failed in November 13, 2000, resulting in a jacket water contamination of the lubricating oil documented in CR 00-3500 and CR 00-3561. The lantern ring was of a “telltale” design, which allowed the leaking fluid to leak to the atmosphere rather than cross contaminating either the oil or jacket cooling water. An engineering evaluation determined that the minor oil leak was due to relaxation of the new type of packing ring (Viton) due to cycling of the system during standby, surveillance test, or maintenance activities.

On March 3, 2004, during a monthly Division 2 EDG surveillance test run, operators identified that the oil leak had taken a step increase to 5 drops per minute during standby condition and over 3 gallons per day (130 drops per minute) while the EDG was running. CR 04-01095 was initiated and a review determined that operability of the EDG was not affected due to the large lubricating oil capacity of the reservoir. An evaluation was performed which established a leakage limit of 224 drops per minute based on the expected oil consumption rate during the EDG mission time. Operator actions were also initiated to monitor and trend engine oil level. Leak repairs were planned for April 2004 during the next scheduled Division 2 EDG outage. Work Order 200005593 for the repair was also coded “Do Not Drop.”

In April 2004 the Division 2 EDG outage was postponed until May 2004. The lubricating oil leak was judged to be acceptable to support the schedule change.

In May 2004 the Division 2 EDG outage was postponed until October 2004. The lubricating oil leak had not measurably degraded, but was judged to be sufficiently high to warrant repair.

On May 21, 2004, the plant was shutdown due to a failure of the 'A' ESW pump. All Division 2 EDG work was postponed. An attempt by the work week manager to repair the EDG lube oil leak during the plant shutdown was denied. On May 24, 2005, operators declared the 'B' ESW pump inoperable but available due to potential common mode failure concerns associated with the 'A' ESW pump failure. The 'B' ESW pump remained available and was actually running for several days. This condition made the Division 2 EDG inoperable, but available if needed.

On May 27, 2004, operators noted that the oil leak had increased to 2 gallons per day with the EDG in a standby condition and CR 04-02768 was generated to identify this issue. No corrective actions were implemented and CR 04-02768 was closed.

On May 29, 2004, while the plant was shutdown, during a scheduled Division 2 EDG monthly surveillance run, the leak was identified at 27 gallons per day which significantly exceeded the 224 drops per minute leakage limit established in March 2004. CR 04-02798 was issued to evaluate this condition. The EDG system engineer determined that although the Division 2 EDG had already been declared inoperable due to the 'B' ESW pump concerns, operability of the EDG could not be supported with this amount of leakage. Therefore, actions were initiated to repair the oil leak.

An engineering evaluation determined that there was sufficient oil in the engine to support the Division 2 EDG mission time. In addition, operator actions could be performed to add oil as needed to support EDG operability for a longer period of time, if necessary. Therefore, the increased leakage would not have prevented the Division 2 EDG from performing its design function if required to do so. The evaluation determined that repair activities were improperly postponed multiple times due to an inadequate focus of the outage management team. The evaluation also concluded that there was industry operating experience available identifying similar leaks and that packing adjustments could have been made periodically to address the leakage.

Analysis: The team determined that the failure to address a Division 2 EDG oil cooler packing leak in a timely manner was a performance deficiency which warranted a significance evaluation. The Mitigating Systems cornerstone was impacted by this issue. The team reviewed the samples of minor issues in IMC 0612, “Power Reactor Inspection Report,” Appendix E, “Examples of Minor Issues,” and determined that there were no examples similar to this issue. In accordance with Appendix B, “Issue Screening,” of IMC 0612, the team determined that the finding was of more than minor significance since the finding was associated with the equipment performance attribute of the Mitigating Systems cornerstone and impacted the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

Using IMC 0609, "Significance Determination Process," Appendix A, "User Guide for Determining the Significance of Reactor Inspection Findings for At-Power Situations," and "SDP Phase 1 Screening Worksheet for Initiating Events, Mitigating Systems, and Barriers Cornerstones," the team determined that this finding 1) was not a design deficiency or qualification deficiency; 2) did not represent an actual loss of safety function of a system; 3) did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time; 4) did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant; and 5) did not screen as potentially risk significant due to seismic, flooding, or a severe weather initiating event. In particular, the condition occurred while the Division 2 EDG was already declared inoperable for an unrelated reason, and the excessive oil leakage condition did not result in an actual failure of the EDG. In addition, the Division 2 EDG remained available to perform its 24 hour mission time, and operator actions could be performed to add oil to support EDG operability for a longer period of time if needed. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

The team also concluded that this finding affected the cross-cutting area of Problem Identification and Resolution because station personnel missed several opportunities to implement repairs but the activities were cancelled. In addition, station personnel failed to recognize available industry experience that indicated that the condition could have been corrected by minor packing adjustments.

<u>Enforcement</u>: Appendix B of 10 CFR 50, Criterion XVI, "Corrective Action," requires, in part, that measures shall be established to ensure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. Contrary to this requirement, station personnel failed to take prompt corrective action to correct a minor oil cooler leak and allowed the leak to degrade further until it affected the reliability and operability of the Division 2 EDG. In addition, station personnel failed to recognize available industry experience that indicated that the condition could have been corrected by minor packing adjustments.

However, because of the very low safety significance of the issue and because the issue has been entered into the licensee's CAP, the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy **(NCV 05000440/2005003-12**). This issue was entered into the licensee's CAP as CR 05-02798.

As part of the licensee's immediate corrective actions, the leak was repaired.

1.10 <u>Failure to Adequately Address Scaffolding Erection Concerns</u>

<u>Introduction</u>: A finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," was NRC-identified when licensee personnel failed to correct an issue regarding the installation of scaffolding erected near safety-related equipment which did not meet the seismic bracing or clearance criteria of licensee procedures.

Description: GCI-0016, "Scaffolding Erection, Modification or Dismantling Guidelines," required an engineering evaluation for scaffolding attached to safety-related supports, friction clamps used for scaffolding in the vicinity of safety-related equipment, or if minimum clearance could not be obtained between safety-related equipment and scaffolding. The engineering evaluation was required to ensure that the equipment would not be adversely impacted due to a seismic event and was requested through a Request-for-Assistance (RFA) CR.

As discussed in IR 05000440/2005002, during a walkdown of the HPCS system, inspectors observed the scaffolding in the Division 3 EDG and HPCS pump rooms failed to meet seismic requirements in GCI-0016. On March 8, 2005, the finding was entered into the licensee's CAP as CR 05-01946. One of the corrective actions (CA 05-01946-1) directed that scaffold supervisors, craft supervisors, foreman review the guidance of GCI-0016 and understand that if the seismic bracing criteria could not be met, a RFA CR would be initiated. None of the corrective actions of CR 05-01946 addressed the extent of condition of the other scaffolding already erected throughout the plant.

On April 4, 2005, the team conducted a walkdown of the Division 1 EDG and the Division 1 EDG support systems. At the time of the inspection, the Division 1 EDG was designated by the licensee as a protected system for shutdown risk. The team noted that scaffolding in the Division 1 EDG room was erected within 1 inch of the crankcase vent piping, was attached to safety-related supports, and utilized friction clamps. The team also noted that the scaffolding had not been evaluated by engineering through an RFA CR. This scaffolding was constructed on March 23, 2005, which demonstrated that the corrective actions to ensure that scaffolding personnel understood the requirements of GCI-0016 were ineffective. The team informed the licensee of the condition and the scaffolding was removed from the Division 1 EDG room.

On two other occasions, scaffolding was identified to be erected in the vicinity of safety-related equipment without meeting the requirements of GCI-0016 and without an engineering evaluation through an RFA CR. The first was licensee-identified and occurred on April 10, 2005, in the LPCS pump room. Two scaffolding erections in the LPCS pump room were observed to be attached to the handrail around the LPCS pump. It was not known when the scaffolding was erected. On the second occasion, on April 12, 2005, an NRC inspector observed scaffolding in the Control Complex 679' elevation near the battery room exhaust fan and the control room supply plenum. These scaffold structures utilized friction clamps and were attached to safety-related supports. These scaffold structures were erected on February 7, 2005, which demonstrated that an adequate extent of condition review of the adverse condition originally identified on March 4, 2005, had not been performed.

Analysis: The team determined that the failure to erect scaffolding in accordance with licensee procedures was a performance deficiency which warranted a significance evaluation. The Mitigating Systems cornerstone was impacted by this issue. The team reviewed the samples of minor issues in IMC 0612, "Power Reactor Inspection Report," Appendix E, "Examples of Minor Issues," and determined that there were no examples similar to this issue. In accordance with Appendix B, “Issue Screening,” of IMC 0612, the team determined that the finding was of more than minor significance since the finding was associated with the equipment performance and human performance attributes of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of equipment that respond to initiating events to prevent undesirable consequences.

Using IMC 0609, “Significance Determination Process,” Appendix A, “User Guide for Determining the Significance of Reactor Inspection Findings for At-Power Situations,” and “SDP Phase 1 Screening Worksheet for Initiating Events, Mitigating Systems, and Barriers Cornerstones,” the team determined that this finding 1) was not a design deficiency or qualification deficiency; 2) did not represent an actual loss of safety function of a system; 3) did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time; 4) did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant; and 5) did not screen as potentially risk significant due to seismic, flooding, or a severe weather initiating event. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

The team also concluded that this finding affected the cross-cutting area of Human Performance because licensee personnel failed to follow both the scaffolding procedure and the temporary alterations procedure. The team also concluded that this finding affected the cross-cutting area of Problem Identification and Resolution because a CAQ regarding scaffolding controls was not promptly corrected.

Enforcement: Appendix B of 10 CFR 50, Criterion XVI, “Corrective Action,” requires, in part, that measures shall be established to ensure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. Contrary to this requirement, the licensee failed to implement adequate corrective actions following unevaluated procedural deviations for scaffolding construction in the Division 3 EDG and HPCS pump rooms. Specifically, an adequate extent of condition evaluation was not performed and misunderstandings of procedure requirements were not adequately addressed. This resulted in several additional unanalyzed conditions where scaffolding failed to meet seismic clearance requirements and thereby degraded the reliability of safety-related equipment.

However, because of the very low safety significance of the issue and because the issue has been entered into the licensee’s CAP, the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (**NCV 05000440/ 2005003-13**). This issue was entered into the licensee’s CAP as CR 05-03027.

As part of the licensee’s immediate corrective actions, the scaffold was immediately removed and all scaffolding erection work was halted and personnel were required to obtain engineering approval of all scaffolding erections, regardless of whether a scaffold erection procedure deviation was identified.

1.11 Failure to Adequately Address EDG Design Concern

Introduction: A finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," was NRC-identified when

licensee personnel failed to adequately address a nonconforming condition in the design of the EDG response to a LOOP signal.

Description: In 2003 during RFO9, the licensee was performing surveillance test SVI-R43T1328 and recorded chattering of the K-1 contactor which provided power to the generator field. It was later determined that the contactor had failed, when the EDG was started for a monthly surveillance run and failed to develop output voltage. Corrective actions included replacing the relay and modifying procedures in order to prevent an intentional connection that would damage the contactor.

In 2004 as part of the EDG latent issues review, CR 04-03463 was initiated to document that for about 2 minutes following an EDG shutdown, the K-1 contactor could chatter and experience the same type of failure as that observed during the monthly surveillance test conducted in RFO9. Specifically, the issue involves the response of the EDG during shutdown from a surveillance test. After the EDG unit output breaker was opened, operators shut down the engine by placing the EDG control switch to "STOP" which then spring returns to "AUTO". Following this action, there was a 2-minute period of vulnerability where the EDG would not re-start on a manual start or automatic LOOP signal generated by the bus under-voltage relays. A manual start or automatic LOOP signal would cause the EDG to roll on air start and lockout. This could result in damage to the K-1 contactor in the generator field circuitry.

An ECR had been initiated to correct the problem. During this inspection, the team noted that the licensee had not implemented the engineering change; but rather relied upon operations procedures to resolve the design deficiency. The engineering change was cancelled upon the determination that the initiating condition was improbable, making the design change unwarranted. The engineering change was determined not to be a regulatory requirement as the licensee considered the EDGs to be in compliance with the design basis.

The licensee's corrective action to address this CR was to add guidance in the procedure to declare the EDG unavailable for 2 to 3 minutes following any surveillance test and avoid simultaneously shutting down both EDGs. The adequacy of the licensee's corrective actions were reviewed by the licensee's Plant Health Committee.

Furthermore, the team reviewed the facility's design and licensing basis information. Perry UFSAR Table 8.1-2 stated, in part, that the application of standby EDGs to the Class 1E power system was in accordance with IEEE Standard 387-1977, "IEEE Standard Criteria for Diesel-Generator Units Applied as Standby Power Supplies for Nuclear Power Generating Stations." IEEE Standard 387-1977, Section 5.6.2.2, "Automatic Control," stated, in part, that upon receipt of a start-diesel signal the automatic control system shall provide automatic startup and automatic adjustment of speed and voltage to a ready to load condition. Furthermore, a start signal shall override all other operating modes and return control of the DG unit to automatic control system, and a start signal shall not override any manual nonoperating modes such as those for repair and maintenance. The licensee's corrective actions and analysis, as described to the team, was not consistent with the IEEE guidance. Additionally, NRC Regulatory Guide 1.108 Section C.1.b.(3) stated that periodic testing of EDG units should not impair the capability of the unit to supply emergency power within the required time. Where necessary, DG unit design should include an emergency override of the test mode to permit response to bona fide signals.

The team was concerned that the licensee' s corrective actions did not fully address the design problem. Since the EDGs were required to be designed such that a LOOP signal should override all other operating modes and return control of the EDG unit to automatic control system, the team considered the as-built design to not be in compliance with the design bases. As the licensee cannot prevent a LOOP signal from occurring during this portion of the test period, it was expected that such an occurrence would render the EDG inoperable until the K-1 contactor could be replaced. This period of time had not been analyzed to meet the required time, therefore, the team considered the design to not be in compliance with the design bases.

Analysis: The team determined that the failure to correct a noncompliance with design requirements was a performance deficiency which warranted a significance evaluation. The Mitigating Systems cornerstone was impacted by this issue. The team reviewed the samples of minor issues in IMC 0612, "Power Reactor Inspection Report," Appendix E, "Examples of Minor Issues," and determined that there were no examples similar to this issue. In accordance with Appendix B, "Issue Screening," of IMC 0612, the team determined that the finding was of more than minor significance since the finding was associated with the design control and equipment performance attributes of the Mitigating Systems cornerstone and adversely impacted the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences because the EDGs could be damaged in response to a LOOP.

Using IMC 0609, "Significance Determination Process," Appendix A, "User Guide for Determining the Significance of Reactor Inspection Findings for At-Power Situations," and "SDP Phase 1 Screening Worksheet for Initiating Events, Mitigating Systems, and Barriers Cornerstones," the team determined that this finding 1) was not a design deficiency or qualification deficiency; 2) did not represent an actual loss of safety function of a system; 3) did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time; 4) did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant; and 5) did not screen as potentially risk significant due to seismic, flooding, or a severe weather initiating event. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

The team also concluded that this finding affected the cross-cutting area of Problem Identification and Resolution because licensee personnel failed to adequately resolve a previously identified CAQ.

Enforcement: Appendix B of 10 CFR 50, Criterion XVI, "Corrective Action," requires, in part, that measures shall be established to ensure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. Contrary to requirement, as of April 7, 2005, the design basis requirements related to EDG response to a LOOP signal had not been correctly translated into the design and this nonconforming condition had not been corrected.

However, because of the very low safety significance of the issue and because the issue has been entered into the licensee’s CAP, the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (**NCV 05000440/ 2005003-14**). This issue was entered into the licensee’s CAP as CR 05-03118.

As part of the licensee’s immediate corrective actions, an engineering change to modify the EDG start circuitry was initiated.

1.12 Failure to Adequately Address ECCW Oiler Concerns

Introduction: A finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," was NRC-identified when licensee personnel failed to adequately review available industry operating experience information and failed to identify degraded oil bubblers that could have adversely impacted the operability of both ECCW pumps.

Description: On March 30 and 31, 2005, during plant tours while the plant was shutdown for a scheduled refueling outage, the team identified that the bottom mounted automatic oil reservoirs (bubblers) for ECCW pumps 1P42C0001A and 1P42C001B as well as control complex chilled water pumps 0P47C0001A, 0P47C0001B, and 0P47C0001C were potentially improperly installed since there were no visible threads at the pipe to oil bubbler base connection. In addition, all of the oil bubbler connections in question had open field deficiencies documenting small oil leaks dating back to 2002. The problem arises when the supply piping nipple for oil bubblers that are bottom mounted and supplied with flat type spider plates was threaded into the oiler base too far. This condition causes the nipple to protrude into the oiler lower base contacting the metal spider and choking off oil flow to the pump bearing. As oil is used by the pump or lost from joint leakage, the oiler would not makeup to the bearing reservoir due to the flow blockage, resulting in bearing damage and pump failure. The oil bubbler vendor re-designed the metal spider by changing from a flat face to a concave shape, thereby increasing the separation between the pipe nipple and the spider to prevent blockage.

The team reviewed the oil bubbler installation/inspection procedure, PMI-0050, "Preventive Maintenance Lubricating Guidelines;" interviewed the control complex system engineer; and reviewed CR 02-00131 to assess the licensee’s response to known industry problems regarding the improper installation of automatic oil bubblers documented in NRC Information Notice 2001-19. The team was concerned since PMI-0050 did not include clear guidance for preventing the oil feed supply nipple from protruding into the oil housing, and the engineering evaluation which was completed in January 16, 2002, per CR 02-00131 did not include field walkdowns or actual inspections to verify proper installation of the oil bubblers. The team raised the concern to plant management and new efforts were initiated (CR 05-03066) to re-inspect the bubblers of concern in the presence of the team. In April 7, 2005, inspections performed by operators and maintenance technicians confirmed that several of the bubblers were improperly installed. Specifically, both bearing bubblers (in-board and outboard) for the 'A' ECCW pump 1P42C0001A and the outboard bearing bubbler for the 'B' ECCW pump 1P42C0001B were installed in such manner that the oil outlet pipe protruded into the oiler base and was in direct contact with the metal spider potentially blocking oil flow. In addition, the inspection revealed that the nipple ends had been machined flat increasing the possibility for oil flow blockage. The team verified that all of the bearings had proper oil level since the oilers did not make up or feed oil to the bearings upon removal of the oil spider.

Analysis: The team determined that the failure to adequately evaluate available industry operating experience regarding improperly installed automatic oil bubblers was a performance deficiency which warranted a significance evaluation. The Mitigating Systems cornerstone was impacted by this issue. The team reviewed the samples of minor issues in IMC 0612, “Power Reactor Inspection Report,” Appendix E, “Examples of Minor Issues,” and determined that there were no examples similar to this issue. In accordance with Appendix B, “Issue Screening,” of IMC 0612, the team determined that the finding was of more than minor significance since the finding was associated with the equipment performance attribute of the Mitigating Systems cornerstone and adversely impacted the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

Using IMC 0609, “Significance Determination Process,” Appendix A, “User Guide for Determining the Significance of Reactor Inspection Findings for At-Power Situations,” and “SDP Phase 1 Screening Worksheet for Initiating Events, Mitigating Systems, and Barriers Cornerstones,” the team determined that this finding 1) was not a design deficiency or qualification deficiency; 2) did not represent an actual loss of safety function of a system; 3) did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time; 4) did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant; and 5) did not screen as potentially risk significant due to seismic, flooding, or a severe weather initiating event. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

The team also concluded that this finding affected the cross-cutting area of Problem Identification and Resolution because licensee personnel missed several opportunities to become aware of the known industry problems associated with improper bubbler installation and failed to identified and adequately resolve a previously identified CAQ.

Enforcement: Appendix B of 10 CFR 50, Criterion XVI, “Corrective Action,” requires, in part, that measures shall be established to ensure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. Contrary to requirement, licensee personnel failed to properly evaluate available industry experience and related maintenance identified problems to ensure proper installation of automatic oil bubblers for safety-related pumps. In addition, technicians, operators, and system engineers missed several opportunities to become aware of the known industry problems associated with improper bubbler installation, and did not identify and correct the improper installation of the oil bubblers. This degraded condition could have affected the operability of both safety ECCW pumps.

However, because of the very low safety significance of the issue and because the issue has been entered into the licensee's CAP, the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (**NCV 05000440/ 2005003-15**). This issue was entered into the licensee's CAP as CRs 05-03066, 05-03109, 05-03110, 05-03104 and 05-02931.

As part of the licensee's immediate corrective actions, a walkdown of all potentially affected oil bubblers was conducted and the bubblers were verified to be able to properly provide makeup oil to ECCW pump bearings.

1.13 Failure to Adequately Address Training Deviation Concerns

Introduction: A finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," was NRC-identified when licensee personnel failed to correct in a timely manner a CAQ regarding operator deviation from training during stressful situations.

Description: As discussed in IP 95002 Supplemental IR 05000440/2004008 dated August 5, 2004, the inspection team identified that the licensee had not identified training as a contributing cause to the September 1, 2003, 'A' ESW pump failure. Subsequently, licensee personnel generated CR 04-03020 to determine why plant employees failed to consistently utilize knowledge and learned skills during stressful events. During a root cause evaluation to address this issue, licensee personnel identified that barriers to prevent events were not always utilized in stressful situations. On August 5, 2004, licensee personnel generated CR 04-04059 to address this issue. Licensee management categorized CR 04-04059 as a "CF", meaning the corrective action would address the condition but no additional causal analysis was required. In September 2004, licensee personnel developed a single corrective action to confirm the problem through the SCWE review scheduled for October 2004. The SCWE report was issued on December 7, 2004, and on December 21, 2004, the licensee extended completion of the corrective actions associated with CR 04-04059 to March 31, 2005, with the rationale that since the SCWE report identified that corrective actions were necessary, the corrective action should remain open until March 31, 2005, when additional corrective actions could be developed. As a result, 8 months had passed and no corrective actions were planned or implemented to ensure licensee personnel utilized knowledge and learned skills during stressful events.

Analysis: The team determined that the failure to develop and implement corrective actions to address licensee personnel deviating from training during stressful times in a timely manner was a performance deficiency which warranted a significance evaluation. The Initiating Events cornerstone was impacted by this issue. The team reviewed the samples of minor issues in IMC 0612, "Power Reactor Inspection Report," Appendix E, "Examples of Minor Issues," and determined that there were no examples similar to this issue. In accordance with Appendix B, "Issue Screening," of IMC 0612, the team determined that the finding was of more than minor significance because the finding could reasonably be viewed as a precursor to a significant event since the continued deviation from established procedures and training during stressful times had the potential to result in an initiating event or result in more significant consequence following an initiating event.

Using IMC 0609, “Significance Determination Process,” Appendix A, “User Guide for Determining the Significance of Reactor Inspection Findings for At-Power Situations,” and “SDP Phase 1 Screening Worksheet for Initiating Events, Mitigating Systems, and Barriers Cornerstones,” for “Transient Initiators,” the team determined that this finding did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

The team also concluded that this finding affected the cross-cutting area of Problem Identification and Resolution because licensee personnel failed to take corrective actions to address a CAQ in a timely manner.

Enforcement: Appendix B of 10 CFR 50, Criterion XVI, “Corrective Action,” requires, in part, that measures shall be established to ensure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. Contrary to this requirement, the licensee failed to take corrective actions for a condition identified in August of 2004 and confirmed to exist in December of 2004. Specifically, although the licensee identified in August 2004 that licensee personnel may deviate from training while under stress and confirmed the condition existed, no corrective actions have been implemented to date.

However, because of the very low safety significance of the issue and because the issue has been entered into the licensee’s CAP, the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy **(NCV 05000440/ 2005003-16)**. The licensee revised CR 04-04059 and entered this issue into their CAP.

As part of the licensee’s immediate corrective actions, human performance tools were implemented which addressed the importance of procedure adherence during events and other stressful situations.

1.14 Failure to Adequately Address ESW Coupling Assembly Concerns

Introduction: A finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action,” was NRC-identified when licensee personnel failed to correct a CAQ identified in IR 05000440/2004008 regarding an NCV for the failure to properly inspect the re-assembly of ESW pump couplings. During this inspection, the team identified that licensee corrective actions to address this issue were inadequate and again failed to prescribe an appropriate inspection of the ESW pump couplings during re-assembly.

Description: As discussed in IP 95002 Supplemental IR 05000440/2004008 dated August 5, 2004, the team identified that work packages used to disassemble and reassemble ESW pumps did not include appropriate quality control sign-offs for the ESW pump couplings that failed. The licensee acknowledged a failure to satisfy NRC requirements committed to in the Quality Assurance Program Manual. In response to this issue, licensee personnel entered this issue into their CAP as CR 04-03026. Prior to RFO10, all corrective actions were implemented with the exception of a corrective action effectiveness review.

During RFO10, the licensee rebuilt ESW pumps 'A' and 'B'. During the reassembly of these pumps, the licensee added witness and hold points to some sections of the work package to reinforce the quality control activities as a barrier to preclude the improper maintenance reassembly of components. However none of these included specific observations of the pump coupling reassembly. This omission was significant since the reassembly of these couplings had proven problematic in the past and was the subject of an NRC finding. Furthermore, although the licensee identified critical points in the reassembly procedure, none of those points received any form of independent inspection. Aside from the very limited QC observations, the only other independent observations were for the landing of thermocouple leads performed by I&C technicians.

In the Quality Assurance Program Manual, the licensee committed to American National Standard (ANS) 45.2.8 for modifications and non-routine maintenance activities. However, licensee procedure NQI-1001, “QC Inspection Program Control,” provided no requirement to perform any inspection other than those specified for special processes such as welding. This procedure included a decision tree chart to assist QC inspectors in determining inspection points for inclusion in a work package. However, the end result for all paths was functionally the same; assign mandatory hold points for activities involving special processes and consider assigning hold points for other activities. The procedure also included criteria from ANS 45.2.8, however its use was not mandatory. Although the Quality Assurance Program Manual allowed for organizations other than QC to perform inspection activities, for the ESW pumps, only QC personnel conducted independent inspections of mechanical assembly.

The team also reviewed the CR associated with the NRC finding. In the licensee’s investigation, the analyst noted that among QC inspectors there was no knowledge of inspections required by ANS 45.2.8. The team discussed corrective actions for this knowledge deficiency with the QC manager who stated that the inspectors had not been trained on the standard, but had been trained on the station QC procedure. Since the licensee’s QC procedure differed significantly from the standard, the team concluded that this knowledge deficiency still existed.

<u>Analysis</u>: The team determined that the failure to prescribe an appropriate inspection of ESW pump couplings during re-assembly was a performance deficiency which warranted a significance evaluation. The Mitigating Systems cornerstone was impacted by this issue. The team reviewed the samples of minor issues in IMC 0612, “Power Reactor Inspection Report,” Appendix E, “Examples of Minor Issues,” and determined that there were no examples similar to this issue. In accordance with Appendix B, “Issue Screening,” of IMC 0612, the team determined that the finding was of more than minor significance since the finding could be reasonably viewed as a precursor to a significant event. Specifically, the licensee failed to perform required inspections for the installation of mechanical equipment and this failure contributed to a previous ESW

pump failure that was determined to be a White finding. The team noted that for both ESW pump failures, the pumps had satisfied post-maintenance testing acceptance criteria. Further, the team noted that improvements in quality control could have detected the conditions that led to premature pump failure. Specifically, inspections could have detected the misalignment of the coupling that led to the first pump failure and improved quality control of parts could have prevented the second failure.

Using IMC 0609, "Significance Determination Process," Appendix A, "User Guide for Determining the Significance of Reactor Inspection Findings for At-Power Situations," and "SDP Phase 1 Screening Worksheet for Initiating Events, Mitigating Systems, and Barriers Cornerstones," the team determined that this finding 1) was not a design deficiency or qualification deficiency; 2) did not represent an actual loss of safety function of a system; 3) did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time; 4) did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant; and 5) did not screen as potentially risk significant due to seismic, flooding, or a severe weather initiating event. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

The team also concluded that this finding affected the cross-cutting area of Problem Identification and Resolution because the finding was associated with the licensee's failure to adequately address a significant condition adverse to quality.

Enforcement: Appendix B of 10 CFR 50, Criterion XVI, "Corrective Action," requires, in part, that measures shall be established to ensure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. Contrary to this requirement, the licensee failed to take corrective actions for quality control deficiencies associated with mechanical installation. Specifically, although the licensee added QC hold points to ESW pump reassembly, those hold points were insufficient to satisfy the requirements of ANS N45.2.8, a condition which was previously the subject of NCV 05000440/2004008-01.

However, because of the very low safety significance of the issue and because the issue has been entered into the licensee's CAP, the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (**NCV 05000440/ 2005003-17**). This issue was entered into the licensee's CAP as CR 05-03655.

As part of the licensee's immediate corrective actions, this issue was entered into the CAP.

2.0 Findings Associated With the Identification of Problems

2.1 Failure to Adequately Address RWCU PCIV Closure Concerns

Introduction: A finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," was NRC-identified when licensee personnel failed to promptly identify, and therefore correct in a timely manner, the condition of the RWCU PCIVs inability to close during all normal and abnormal conditions.

Description: On December 14, 2004, the RWCU outboard PCIV to the condenser failed to close when licensee personnel secured the system. The inboard valve did successfully close and licensee personnel were subsequently able to close the outboard isolation valve. The licensee declared the outboard valve inoperable and performed the actions prescribed by TSs for an inoperable PCIV. Licensee personnel concluded the valve failed to close as a result of improper functioning of a torque switch in the valve actuator. Licensee personnel had determined that the valve was only required to close against a differential pressure of 140 pounds per square inch (psi). However, during this particular evolution, actual differential pressure across the valve exceeded 1000 psi. The system was configured such that pressure dropped as reactor coolant flowed past a nonsafety-related throttle valve and an orifice. However, as the PCIV closed it became more restrictive to flow and differential pressure across the PCIV increased dramatically while that across other components decreased. During this operation of the system, licensee personnel closed the upstream nonsafety-related throttle valve expecting to stop most or all flow through the PCIVs. In this case, although the valve was closed, significant seat leakage existed that resulted in a higher than expected differential pressure across the PCIV.

During the investigation of the failure of the PCIV to close, the licensee identified an earlier instance where a similar failure had occurred. In 1994 the same valve failed to close under similar circumstances. In that case, licensee personnel erroneously concluded that a repair of the throttle valve was sufficient to correct the deficiency. In both of the 1994 and 2004 events, the throttle valve experienced seat leakage. Licensee discussions with the valve manufacturer revealed that the valve was designed to throttle flow and therefore some leakage should always be expected.

Generic Letter 89-10 required licensees to review design basis maximum differential pressures, establish correct switch settings for identified differential pressures, and perform testing at the design flow and/or differential pressure settings to verify operability of MOVs during normal and abnormal conditions. Licensee personnel had not demonstrated that these PCIVs could close under normal design flows but instead, documented instances where a valve did not close under a less restrictive lower flow condition. In addition, during accident conditions, the PCIVs would close upon receipt of certain signals. However, no safety-related controls existed to ensure flow had stopped such that the PCIVs could close.

Analysis: The team determined that the failure to ensure that the RWCU PCIV could function under all operating conditions was a performance deficiency which warranted a significance evaluation. The Barrier Integrity cornerstone was impacted by this issue. The team reviewed the samples of minor issues in IMC 0612, “Power Reactor Inspection Report,” Appendix E, “Examples of Minor Issues,” and determined that there were no examples similar to this issue. In accordance with Appendix B, “Issue Screening,” of IMC 0612, the team determined that the finding was of more than minor significance since the finding was associated with the RCS equipment and barrier performance attribute of the barrier cornerstone and affected the cornerstone objective of providing reasonable assurance that physical design barriers protect the public from radio nuclide releases caused by accidents or events. Specifically, PCIVs were required to close under normal and abnormal conditions and the outboard RWCU PCIVs would not close when securing from a normal RWCU lineup.

Using IMC 0609, “Significance Determination Process,” Appendix A, “User Guide for Determining the Significance of Reactor Inspection Findings for At-Power Situations,” and “SDP Phase 1 Screening Worksheet for Initiating Events, Mitigating Systems, and Barriers Cornerstones,” the team determined that this finding 1) did not represent a degradation of the radiological barrier function of the control room, auxiliary building, spent fuel pool, or annulus exhaust gas treatment system; 2) did not represent a degradation of the barrier function of the control room against smoke or toxic gas; 3) did not represent an actual open pathway in the physical integrity of the containment; and 4) did not involve an actual reduction in the defense-in-depth for the atmospheric pressure control or the hydrogen control functions of containment. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

The team also concluded that this finding affected the cross-cutting area of Problem Identification and Resolution because licensee personnel failed to correct the condition of the valve not closing under both normal and accident conditions.

Enforcement: Appendix B of 10 CFR 50, Criterion XVI, “Corrective Action,” requires, in part, that measures shall be established to ensure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. Contrary to this requirement, the licensee failed to adequately correct the deficient condition of PCIVs not being able to close under all normal and abnormal conditions. In particular, on December 14, 2004, the outboard RWCU PCIV failed to close when securing from a normal condition.

However, because of the very low safety significance of the issue and because the issue has been entered into the licensee’s CAP, the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (**NCV 05000440/ 2005003-18**). This issue was entered into the licensee’s CAP as CR 05-06581.

To address this issue, licensee personnel initiated actions to improve the performance margin of the affected valves and review calculations to clarify the design and licensing basis.

2.2 Failure to Adequately Address Breaker Testing Concerns

Introduction: A finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action,” was NRC-identified when licensee personnel failed to initiate a CR to identify a CAQ following an error in the performance of a safety-related breaker overcurrent device calibration procedure step. After the breaker failed to trip as required, the technicians identified the error and re-performed 11 procedure steps. However, the technicians stated that they did not intend to initiate a CR to document the error and did not identify the error in the narrative log provided with the procedure until prompted the following day by the team.

Description: On March 16, 2005, while observing electrical maintenance personnel perform safety-related 480 VAC breaker EF1D12 overcurrent trip testing prescribed by WO 20087868 in accordance with procedure GEI-0124, “Types SS-3, SS-4, SS-5 Solid State Trip Devices Testing and Calibration Using Multi-Amp CB-8160 Test Set,” the team observed the breaker failed to trip as required in step 5.2.5.5 of the procedure. Immediate investigation by the electricians identified that external auxiliary voltage source leads had been improperly attached during step 5.2.4.2. The leads were appropriately attached, 11 procedure steps were re-performed, and the breaker was re-tested satisfactorily.

On March 17, 2005, the team noted that a CR had not been initiated in accordance with Section 4.3.6 of procedure NOP-LP-2001, “Condition Report Process.” NOP-LP-2001 required that “A condition report shall be initiated upon discovery of any degraded conditions that affect USAR [Updated Safety Analysis Report] described systems, structures or components.” In addition, Attachment 1, “Procedures, Conditions Adverse to Quality” of NOP-LP-2001 listed, “Failure to follow or use required procedures/instructions,” as a condition warranting the initiation of a CR.

The issue of not initiating a required CR for the failure to properly follow the procedure step was discussed with maintenance management. As a result, on March 18, 2005, CR 05-02420 which described the inadequately performed procedure step was initiated. However, the CR stated that because the electricians had re-performed the steps that, “No further actions are required.” Discussions indicated that the immediate first-line supervisor did not believe the issue warranted the initiation of a CR. The team pointed out that the reason for initiating a CR included identification of the cause for the incorrectly performed step to prevent recurrence. In this case the team had noted that one electrician was reading and marking the procedure steps when completed and the other two electricians were performing the tasks. However, the electrician reading the steps did not always verify that steps were completed as required before marking the steps as complete and for step 5.2.4.2, did not verify the step was complete prior to marking the step as complete. Another observation was that the informal nature of the communications between the three electricians may have contributed to the error, particularly since the procedure reader did not verify that the steps were completed as they were read. As a result, licensee personnel initiated CR 05-02583 to identify this issue.

Analysis: The team determined that the failure to initiate a CR to identify a condition that was adverse to quality was a performance deficiency which warranted a significance evaluation. The Mitigating Systems cornerstone was impacted by this issue. The team reviewed the samples of minor issues in IMC 0612, “Power Reactor Inspection Report,” Appendix E, “Examples of Minor Issues,” and determined that there were no examples similar to this issue. In accordance with Appendix B, “Issue Screening,” of IMC 0612, the team determined that the finding was of more than minor significance because the ineffective implementation of procedure steps by maintenance, if left uncorrected, could become a more significant safety concern since safety-related equipment would not be properly tested, reassembled, or maintained.

Using IMC 0609, “Significance Determination Process,” Appendix A, “User Guide for Determining the Significance of Reactor Inspection Findings for At-Power Situations,” and “SDP Phase 1 Screening Worksheet for Initiating Events, Mitigating Systems, and Barriers Cornerstones,” the team determined that this finding 1) was not a design deficiency or qualification deficiency; 2) did not represent an actual loss of safety function of a system; 3) did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time; 4) did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant; and 5) did not screen as potentially risk significant due to seismic, flooding, or a severe weather initiating event. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

The team also concluded that this finding affected the cross-cutting area of Problem Identification and Resolution because licensee personnel failed to generate a CR to identify a CAQ which adversely impacted the licensee’s ability to take effective corrective actions to address the issue.

Enforcement: Appendix B of 10 CFR 50, Criterion XVI, “Corrective Action,” requires, in part, that measures shall be established to ensure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and non-conformances are promptly identified and corrected. Contrary to this requirement, on March 16, 2005, during safety-related 480 Vac breaker EF1D12 overcurrent trip testing prescribed by WO 20087868, and conducted in accordance with procedure GEI-0124, “Types SS-3, SS-4, SS-5 Solid State Trip Devices Testing and Calibration Using Multi-Amp CB-8160 Test Set,” and following a failure to properly complete procedure step 5.2.4.2 in procedure GEI-0124, the licensee failed to initiate a CR to identify a CAQ.

However, because of the very low safety significance of the issue and because the issue has been entered into the licensee’s CAP, the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (**NCV 05000440/ 2005003-19**). This issue was entered in the licensee’s CAP as CR 05-02420 and CR 05-02583.

As part of the licensee’s immediate corrective actions, the testing leads were properly attached, 11 procedure steps were re-performed, and the breaker was re-tested satisfactorily.

3.0 Findings Associated With Procedure Adherence Issues

3.1 Failure to Comply With ARC Procedure During EDG Modifications

Introduction: The team identified a finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” was NRC-identified when licensee personnel failed to adhere to procedures used for the modification of safety-related equipment and modified a portion of the Division 1, 2, and 3 EDG exhaust ventilation system without declaring the ventilation system unavailable, as required.

Description: On April 7, 2005, in response to an NRC observation regarding improper use of the ARC process for modifications to the EDG missile shield, the licensee revised their ARC process to permit use of the process on structures. As part of a compliance review for the revised process, the licensee performed an inspection of previously installed insulation. During this inspection, the licensee noted that insulation had been installed not only on the missile barrier structure but on the EDG exhaust pipe as well. By procedure, the ARC process cannot be used on in service systems. In addition, when the ARC process was used, the affected system must be physically isolated by a clearance. Upon discovery of the installed insulation, licensee personnel declared all three divisions of EDGs inoperable and removed the prematurely installed insulation. The licensee submitted, and subsequently retracted, a Licencee Event Report (LER) to the NRC. In the LER retraction, the licensee stated that an evaluation confirmed that the additional weight of the insulation on the exhaust piping had no impact on EDG operability.

Analysis: The team determined that the failure to adhere to procedures used for the modification of safety-related equipment and modified a portion of the Division 1, 2, and 3 EDG exhaust ventilation system without declaring the ventilation system unavailable was a performance deficiency which warranted a significance evaluation. The Mitigating Systems cornerstone was impacted by this issue. The team reviewed the samples of minor issues in IMC 0612, "Power Reactor Inspection Report," Appendix E, "Examples of Minor Issues," and determined that there were no examples similar to this issue. In accordance with Appendix B, "Issue Screening," of IMC 0612, the team determined that the finding was of more than minor significance since the finding was associated with the configuration control attribute of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

Using IMC 0609, "Significance Determination Process," Appendix A, "User Guide for Determining the Significance of Reactor Inspection Findings for At-Power Situations," and "SDP Phase 1 Screening Worksheet for Initiating Events, Mitigating Systems, and Barriers Cornerstones," the team determined that this finding 1) was not a design deficiency or qualification deficiency; 2) did not represent an actual loss of safety function of a system; 3) did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time; 4) did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant; and 5) did not screen as potentially risk significant due to seismic, flooding, or a severe weather initiating event. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

The team also concluded that this finding affected the cross-cutting area of Human Performance since licensee personnel failed to adhere to ARC procedure associated with the modification activities.

Enforcement: Appendix B of 10 CFR 50, Criterion V, "Instructions, Procedures and Drawings," requires, in part, that activities affecting quality shall be prescribed by instructions, procedures, and drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, and drawings. NOP-CC-2003 stated, in part, that "ARCs [At-Risk-Changes] shall only be used to alter or modify SSCs [structures, systems, and components] that are out of service and physically isolated (i.e. clearance posted) from electrical and mechanical sources. ARCs shall not be used to modify any portion of an in service or operable (i.e. energized, pressurized) SSC." The procedure also stated, "Once an ARC is issued and field implementation has commenced, the system shall be considered 'out of service' and shall not be energized, operated, tested (other than continuity, manual rotation or similar non-energized/filled/loaded conditions), or considered 'available' until the formal Engineering Change Package or Revision Notice is issued for implementation." Contrary to these requirements, the licensee implemented an ARC to the EDG exhaust piping without declaring EDGs inoperable and without physically isolating the EDG exhaust.

However, because of the very low safety significance of the issue and because the issue has been entered into the licensee's CAP, the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (**NCV 05000440/ 2005003-20**). This issue was entered into the licensee's CAP as CR 05-03126.

As part of the licensee's immediate corrective actions, the EDGs were declared inoperable until the modification was removed.

3.2 Improperly Performed Verification of Electrical Disconnect Status

Introduction: A finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was self-revealed when licensee personnel improperly performed a procedure step for verification of the position of RCIC system electrical control disconnects.

Description: On February 26, 2005, an operator performed step 7 and step 8 of surveillance testing procedure SVI-E51-T1298, which verified that the RCIC system was in a "secured status" with the five electrical disconnects in a "closed" position. The operator signed the procedure steps indicating that he had verified that all five disconnects were in the "closed" position. However; all five disconnects were actually in the "open" position. During the performance of subsequent steps in the surveillance testing procedure, an I&C technician noted problems and appropriately stopped the surveillance. It was subsequently identified that the disconnects were incorrectly positioned.

Analysis: The team determined that the failure to properly perform a procedure step for verification of the position of RCIC system electrical control disconnects was a performance deficiency which warranted a significance evaluation. The Mitigating Systems cornerstone was impacted by this issue. The team reviewed the samples of minor issues in IMC 0612, "Power Reactor Inspection Report," Appendix E, "Examples of Minor Issues," and determined that there were no examples similar to this issue. In accordance with Appendix B, "Issue Screening," of IMC 0612, the team determined that the finding was of more than minor significance since the finding was associated with the configuration control and human performance attributes of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

Using IMC 0609, “Significance Determination Process,” Appendix A, “User Guide for Determining the Significance of Reactor Inspection Findings for At-Power Situations,” and “SDP Phase 1 Screening Worksheet for Initiating Events, Mitigating Systems, and Barriers Cornerstones,” the team determined that this finding 1) was not a design deficiency or qualification deficiency ; 2) did not represent an actual loss of safety function of a system; 3) did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time; 4) did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant; and 5) did not screen as potentially risk significant due to seismic, flooding, or a severe weather initiating event. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

The team also concluded that this finding affected the cross-cutting area of Human Performance because licensee personnel failed to adhere to procedure steps for aligning RCIC systems electrical disconnects.

Enforcement: Appendix B of 10 CFR 50, Criterion V, “Instructions, Procedures, and Drawings,” requires, in part, that activities affecting quality shall be prescribed by instructions, procedures, and drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, and drawings. Contrary to this requirement, on February 26, 2005, licensee failed to accomplish procedural step 7 and step 8 of surveillance testing procedure SVI-E51-T1298 and failed to properly verify the position of five electrical disconnects.

However, because of the very low safety significance of the issue and because the issue has been entered into the licensee’s CAP, the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (**NCV 05000440/ 2005003-21**). This issue was entered into the licensee’s CAP as CR 05-01511.

As part of the licensee’s immediate corrective actions, the electrical disconnects were properly positioned.

3.3 Improperly Performed Verification of Electrical Jumper Removal

Introduction: A finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” was self-revealed when maintenance personnel improperly performed a procedure step for verification that jumpers had been removed from an electrical cabinet.

Description: On March 16, 2005, licensee personnel performed jumper removal activities in accordance with procedure SOI-M14, “Containment Vessel and Drywell Purge System.” Based upon a review of the narrative logs, the correct task description was used, however procedure section 6.2 was referenced instead of procedure Section 6.4, as required. Section 5.7.1 of SOI-M14 directed operators to shutdown the CVDWP system by completing the applicable sections of either 6.2 or 6.4, as appropriate. In preparations for performing operations in accordance with SOI-M14, Section 4.2, “Startup to Refuel Mode,” on March 17, 2005, licensee personnel searched for a special jumper that should have been removed on March 16. This jumper was needed for a related task. During their search for the jumper, licensee personnel identified that it was still installed in the electrical cabinet. A review of the completed verification sheets was performed and it was noted that Section 6.2 had been completed instead of Section 6.4, as required. Section 6.4, step 9, would have removed the jumper and would have required the operators to independently verify that the jumper was removed. On March 17, 2005, the section 6.4 was completed and the jumper was removed. The jumper affected the operation of the drywell purge system isolation damper.

Analysis: The team determined that the failure to properly perform a procedure step for verification that jumpers had been removed from an electrical cabinet was a performance deficiency which warranted a significance evaluation. The Mitigating Systems cornerstone was impacted by this issue. The team reviewed the samples of minor issues in IMC 0612, "Power Reactor Inspection Report," Appendix E, "Examples of Minor Issues," and determined that there were no examples similar to this issue. In accordance with Appendix B, "Issue Screening," of IMC 0612, the team determined that the finding was of more than minor significance since the finding was associated with the configuration control and human performance attributes of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

Using IMC 0609, "Significance Determination Process," Appendix A, "User Guide for Determining the Significance of Reactor Inspection Findings for At-Power Situations," and "SDP Phase 1 Screening Worksheet for Initiating Events, Mitigating Systems, and Barriers Cornerstones," the team determined that this finding 1) was not a design deficiency or qualification; 2) did not represent an actual loss of safety function of a system; 3) did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time; 4) did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant; and 5) did not screen as potentially risk significant due to seismic, flooding, or a severe weather initiating event. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

This team also concluded that this finding affected the cross-cutting area of Human Performance because licensee personnel improperly performed a procedure step for verification that jumpers had been removed from an electrical cabinet.

Enforcement: Appendix B of 10 CFR 50, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality shall be prescribed by instructions, procedures, and drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, and drawings. Contrary to this requirement, on March 16, 2005, the licensee failed to implement the applicable procedure section of SOI-M14 as required by Section 5.7, which resulted in failure to remove an electrical jumper in the control circuit of the drywell purge isolation damper.

However, because of the very low safety significance of the issue and because the issue has been entered into the licensee's CAP, the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy

(**NCV 05000440/ 2005003-22**). This issue was entered into the licensee's CAP as CR 05-03275.

As part of the licensee's immediate corrective actions, the electrical jumper was removed from the electrical cabinet.

4.0 Findings Associated With Design Control Issues

4.1 Inadequate Testing Following "Hot Short" Modifications

Introduction: A finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion III, "Design Control," was NRC-identified when licensee personnel failed to conduct adequate post-modification testing to verify the adequacy of a design change which modified the control circuit of a RHR system valve.

Description: In response to NRC Information Notice 92-18, "Potential for Loss of Remote Shutdown Capability During a Control Room Fire," licensee personnel performed modifications to about 30 MOVs to eliminate susceptibility to damage resulting from a postulated fire-induced short circuit. Seven of the modified valves were controlled either from the main control room or from the RSP, depending on the position of the RSP emergency transfer switch associated with the valve. The purpose of the RSP switch was to transfer valve control to the RSP, and to isolate control cables between the RSP and the main control room to ensure that fire-induced damage from a ground or a hot short could not impact valve operability from the RSP. DCP 99-5011A performed this modification for RHR valve E12-F011A in 2000.

As part of the modification, RSP transfer switch contacts were re-wired on the switch, and a previously unused set of switch contacts were wired into the MOV closing circuit. The team determined that the isolation function of the emergency transfer switch had been affected by the modification work. The post-modification test included point-to-point wiring checks, valve stroke testing, and a functional check of valve control both from the main control room and from the RSP. However, the point-to-point wiring checks did not include the RSP transfer switch portion of the affected circuitry, and the functional checks did not verify that with the transfer switch in the emergency position that the control room wiring was isolated from the RSP wiring. The team identified that no verification of the emergency transfer switch isolation function had been performed by the modification testing, or by any subsequent testing following the modification. During an extent of condition review, licensee personnel determined that this post-modification testing had not been performed to six other RSP valves subject to this type of modification.

Analysis: The team determined that the failure to conduct adequate post-modification testing to verify the adequacy of a design change which modified the control circuit of a RHR system valve was a performance deficiency which warranted a significance evaluation. The Mitigating Systems cornerstone was impacted by this issue. The team reviewed the samples of minor issues in IMC 0612, “Power Reactor Inspection Report,” Appendix E, “Examples of Minor Issues,” and determined that there were no examples similar to this issue. In accordance with Appendix B, “Issue Screening,” of IMC 0612, the team determined that the finding was of more than minor significance since the finding was associated with the equipment performance and procedure quality attributes of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, licensee personnel did not verify that the isolation function of the RSP emergency transfer switch was operable after a modification rewired the switch and placed a previously unused set of contacts in the isolation circuit. The team determined that a missed modification acceptance test was more significant than a missed surveillance test because, unlike a surveillance test which verifies continued component operability, a modification acceptance test establishes initial component operability. In addition, this was not an isolated example, since six other similar modifications also did not perform an adequate post modification test of the RSP emergency transfer switch isolation function.

Using IMC 0609, “Significance Determination Process,” Appendix F, "Fire Protection Significance Determination Process," the team reviewed the finding against the Phase 1 Qualitative Screening criteria. The severity of the deficiency was determined to have a low degradation rating, because the reliability of the system function impacted by the finding was not significant (subsequent testing determined the switch isolation function was operable). Therefore, the finding screened as Green and was considered to be of only very low safety significance.

Enforcement: Appendix B of 10 CFR 50, Criterion III, “Design Control,” requires, in part, that measures shall be established to assure that applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures and instructions, and that design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program. Contrary to this requirement, licensee personnel failed to verify the adequacy of design for a modification to a MOV control circuit. Specifically, DCP 99-5011A modified the control circuit for RHR valve E12-F011A, which included wiring and contact changes to the RSP emergency transfer switch. However, licensee personnel failed to properly verify that the isolation function of the RSP emergency transfer switch remained operable following the completion of the modification activities.

However, because of the very low safety significance of the issue and because the issue has been entered into the licensee’s CAP, the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (**NCV 05000440/ 2005003-23**). This issue was entered into the licensee’s CAP as CR 05-03112.

As part of the licensee’s immediate corrective actions, licensee personnel verified the adequacy of the design modification through the performance of a suitable test.

4.2 Inadequate Safe Shutdown MOV Design Change Assessment

Introduction: A finding of very low safety significance (Green) and an associated NCV of Perry Operating License Condition 2.C(6), "Fire Protection," was NRC-identified when licensee personnel revised the fire protection program, but did not perform an adequate assessment to verify those changes did not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

Description: NRC Information Notice 92-18, "Potential for Loss of Remote Shutdown Capability During a Control Room Fire," identified that MOVs important for safe shutdown, could receive spurious control signals during a postulated control room fire, before an operating crew had sufficient time to evacuate the control room and transfer emergency control to a RSP. As a result, valve or valve operator damage could occur before the fire damaged portion of the circuit was isolated from the RSP.

Licensee personnel evaluated plant design for the identified susceptibilities in PIF 96-2458, "IN 92-18 Evaluation," and calculation SQ-0093, "Stall Thrust Evaluation for IN 92-18." Where physical damage could occur (i.e., weak link analysis), MOV control circuits needed for safe shutdown were modified to eliminate susceptibility to fire damage.

Licensee personnel determined that for MOVs not susceptible to physical damage by weak link analysis, only the electrical motor needed to be protected to prevent motor burnout due to locked rotor current. Calculations concluded that by reducing the fuse size, the fuses would open in sufficient time to prevent motor damage from fire induced spurious operation. Licensee personnel reasoned that the fuses could be changed, as needed, to return the MOV to service. The team noted that the licensee evaluations appeared to conclude that those manual actions were the same as maintaining the circuits free of fire damage.

Three ESW MOVs required for hot shutdown were not protected from fire damage. The 'A' ESW pump discharge valve P45-F130A was required to automatically open, when the 'A' ESW pump started. The other two valves, P45-F014A and P45-F068A, were required to remain open to supply cooling water to the RHR heat exchanger for suppression pool cooling. Licensee personnel relied on fuse replacement to restore RSP control of those MOVs after any fire damage. Fuses were pre-staged in the RSP room.

The team identified that there were no procedures to implement the necessary manual actions. Specifically, there were no instructions, notes, cautions, or prerequisites in any procedure to diagnose, identify, or replace the fuses. As an immediate corrective action, licensee personnel revised IOI-011, "Shutdown from Outside the Control Room," to include instructions to diagnose for blown fuses, and replace fuses as appropriate. The licensee entered this issue into their CAP as CR 05-04078.

The decision to deviate from the required protective feature (i.e., maintain circuits free of fire damage) relied upon a compensating alternative protection measure (i.e., fuse replacement) to restore the fire damaged circuits. The team identified that the licensee's evaluation did not comply with the regulatory guidance for performing an adverse affect assessment, in accordance with Generic Letter 86-10, "Implementation of Fire Protection Requirements." For the manual actions credited by the safe shutdown capability repair, the specific issues included:

- Did not translate design basis requirements into operating instructions.
- Did not verify or validate adequate time to perform the manual actions.
- Did not perform any operator training on the specific manual actions.
- Did not verify adequate emergency lighting at the specific work locations.
- Did not verify component access (e.g., was a ladder needed).
- Did not consider pre-staged repair parts for all manual actions.
- Did not perform any fire protection review for P45-E14A. Licensee personnel determined no design change was needed because the original fuse size was adequate to protect the motor.

Licensee personnel subsequently identified that if the 'A' ESW train became temporarily unavailable, then the Division 1 EDG would trip within a few minutes on high jacket water temperature. The ESW pump house, a normally unoccupied area, was the location for the manual action to replace the P45-F130A fuses. In addition, the Division 2 EDG and 'B' ESW trains were not protected from fire damage following a control room fire. Licensee personnel subsequently determined that the potential loss of an EDG may not have been considered in the original evaluation to substitute manual actions, in place of maintaining the circuits free of fire damage. The licensee entered this issue into their CAP as CR 05-04346.

Fire protection requirements specify that components necessary to achieve and maintain hot shutdown shall be free of fire damage (FSAR Section 9A.6, Appendix R III.G compliance). In addition, requirements specified that safe shutdown must be achieved with or without offsite power (FSAR Section 9A.3.1). PNPP Operating License, Condition 2.C(6), allowed changes to the approved fire protection program without prior NRC approval, only if those changes did not adversely impact the ability to achieve and maintain safe shutdown in the event of a fire.

Based on the above information, the team determined that the licensee's evaluation did not demonstrate that an equivalent level of protection would be achieved. Specifically, the licensee's determination had not evaluated the adequacy of procedures or training to perform the actions, and had not verified or validated whether there was adequate time to perform the actions prior to occurrence of an adverse consequence, such as a temporary loss of ESW, which could result in a loss of an EDG. Therefore, the team concluded that licensee personnel had approved deviations to Appendix-R III.G requirements without an adequate review to demonstrate there were no adverse affects to the ability to achieve and maintain safe shutdown.

Analysis: The team determined that the revision of the fire protection program without an adequate assessment to verify those changes did not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire was a performance deficiency which warranted a significance evaluation. The Mitigating Systems cornerstone was impacted by this issue. The team reviewed the samples of minor issues in IMC 0612, "Power Reactor Inspection Report," Appendix E, "Examples of Minor Issues," and determined that there were no examples similar to this issue. In accordance with

Appendix B, “Issue Screening,” of IMC 0612, the team determined that the finding was of more than minor significance since the finding was associated with the design control, equipment performance, and procedure quality attributes of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, licensee personnel substituted manual actions, in lieu of keeping the circuits free of fire damage, but did not adequately assess the ability to perform the actions and did not verify or validate adequate time to perform the actions.

Using IMC 0609, “Significance Determination Process,” Appendix F, "Fire Protection Significance Determination Process," the team reviewed the finding against the Phase 1 Qualitative Screening criteria. The Phase 1 screening determined that a Phase 2 evaluation was required because the severity of the deficiency (e.g., inadequate instructions to diagnose and repair, or insufficient time to perform credited actions) was determined to have a moderate degradation rating. The degraded reliability could have had a significant impact on system performance. In the Phase 2 Quantitative Screening, a post-fire safe shutdown category was assigned, and a fire damage state 2 scenario was determined to apply. The fire ignition source associated with this deficiency was characterized as electrical cabinets. A fire ignition source screening determined this deficiency did not result in ignition of secondary combustible fuels, and did not cause damage consistent with the fire damage state scenario of interest. Therefore, the Phase 2 screening determined this finding was of very low safety significance (Green), because no potentially challenging fire scenarios were developed.

<u>Enforcement</u>: Condition 2.C(6) of the PNPP Operating License NPF-58,"Fire Protection," required, in part, that FENOC shall implement and maintain all provisions of the approved fire protection program, as described in the UFSAR. The license condition also stated that FENOC may make changes to the approved fire protection program without prior Commission approval only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire. UFSAR, Section 9A.6 which stated that PNPP complied with 10 CFR 50, Appendix R, Section III.G, "Fire Protection of Shutdown Capability." Appendix R, Section III.G required, in part, that fire protection features shall be capable of limiting fire damage so that systems necessary to achieve and maintain hot shutdown conditions were free of fire damage. In addition, UFSAR Section 9A.3.1, stated that, for the fire hazards analysis, only the Class 1E power sources (i.e., EDG) had been analyzed.

Contrary to the above requirements, FENOC revised the fire protection program without an adequate determination that the changes did not adversely affect the ability to achieve and maintain safe shutdown. Specifically, in 1996, for MOVs P45-F014A, F068A, & F130A, FENOC deviated from the requirement to maintain hot shutdown circuits free of fire damage, and substituted manual actions to recover from fire damage. The licensee’s evaluation was inadequate because it did not adequately assess the ability to perform the actions and did not verify or validate adequate time to perform the actions. In addition, no evaluation was performed for P45-F014A. As a result, operating procedures did not provide instructions to diagnose and recover from fire damage, and a temporary loss of ESW could result in a loss of the associated EDG.

However, because of the very low safety significance of the issue and because the issue has been entered into the licensee's CAP, the issue is being treated as NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (**NCV 05000440/2005003-24**). This issue was entered into the licensee's CAP as CRs 05-04078 and 05-4346.

As part of the licensee's immediate corrective actions, procedure SOI-C61 and IOI-0011 was revised to add the affected fuses to the remote shutdown inventory and provide guidance regarding fuse replacement.

4.3 Failure to Adequately Consider the Environmental Impact on TRD Modification

Introduction: A finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion III, "Design Control," was NRC-identified when licensee personnel failed to adequately evaluate the effect of water intrusion on the insulation composite installed in the EDG exhaust enclosure.

Description: The licensee implemented ECP 05-0032 to insulate the EDG safety-related exhaust enclosure. The purpose of this insulation modification was to ensure that the concrete of the exhaust enclosure did not exceed a temperature of 150 °F during normal operations and 350 °F during accident conditions, as described in the UFSAR. This modification also removed the existing TRDs. The TRDs were designed to open and provide a safety-related diesel exhaust path into the exhaust enclosure in the event the normal nonsafety-related exhaust path became blocked. Perry included removal of the TRDs in this modification due to their history of unreliability. Implementation of this modification resulted in a passive safety-related exhaust system for the Division 1, 2, and 3 EDGs.

The insulation composite consists of four layers of one-inch thick micro-porous insulation sandwiched between two layers of stainless steel. The insulation composite was mounted on unistruts from the walls of the EDG concrete exhaust enclosure. Portions of the insulated enclosure were exposed to various weather conditions, such as rain and snow, through four screened openings.

Documentation supplied by the vendor stated that water intrusion could adversely affect the thermal quality of the insulation. The documentation also stated that the only method to determine if there has been any degradation is to measure the thickness of the material and/or to ensure that the product did not become wet. Following review of the modification package and multiple walkdowns of the exhaust enclosure, the team discovered that licensee personnel had not included any analysis of the potential effects of water intrusion in the modification package or in any of the associated calculations. The team also identified some areas in the exhaust enclosure where insulation was directly exposed, making the insulation more susceptible to water intrusion.

Licensee personnel developed an engineering evaluation and concluded, based on additional vendor information, that if all four layers of insulation were to become totally soaked with water, the thermal conductivity of the insulation would increase by 25 percent to 50 percent. An increase in thermal conductivity could result in an increase in concrete wall temperatures greater than the specified limits. Therefore, licensee personnel re-calculated concrete wall temperatures, assuming this increase in thermal conductivity, and determined that the concrete would still be less than the required temperature limits.

Analysis: The team determined that the failure to adequately evaluate the effect of water intrusion on the insulation composite installed in the EDG exhaust enclosure was a performance deficiency which warranted a significance evaluation. The Mitigating Systems cornerstone was impacted by this issue. The team reviewed the samples of minor issues in IMC 0612, “Power Reactor Inspection Report,” Appendix E, “Examples of Minor Issues,” and determined that there were no examples similar to this issue. In accordance with Appendix B, “Issue Screening,” of IMC 0612, the team determined that the finding was of more than minor significance since the finding was associated with the design control attribute of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

Using IMC 0609, “Significance Determination Process,” Appendix A, “User Guide for Determining the Significance of Reactor Inspection Findings for At-Power Situations,” and “SDP Phase 1 Screening Worksheet for Initiating Events, Mitigating Systems, and Barriers Cornerstones,” the team determined that this finding was a design deficiency or qualification deficiency confirmed not to result in a loss of function per Generic Letter 91-18. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

Enforcement: Appendix B of 10 CFR 50, Criterion III, “Design Control,” requires, in part, that measures shall be established to assure that applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures and instructions, and that design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program. Contrary to this requirement, licensee personnel failed to adequately consider the effects of water intrusion on the insulation composite for the DG exhaust enclosure modification. This resulted in Perry having to recalculate expected concrete temperatures, taking into account wetted insulation.

However, because of the very low safety significance of the issue and because the issue has been entered into the licensee’s CAP, the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy **(NCV 05000440/ 2005003-25)**. This issue was entered into the licensee’s CAP as CR 05-04093.

As part of the licensee’s immediate corrective actions, engineering personnel re-calculated expected concrete temperatures, taking into account wetted insulation.

5.0 Findings Associated With Emergency Preparedness

5.1 Inappropriate Use of the HP Technician as the Interim OSC Coordinator

Introduction: A finding of very low safety significance and an associated Severity Level IV NCV of 10 CFR 50.54(q) was NRC-identified when licensee personnel failed to obtain prior NRC approval for a changes to the Perry Emergency Plan concerning ERO staffing and response timeliness.

Description: Procedure EPI-A7, "Operations Support Center Activation," Attachment 1, “OSC Activation Checklist,” stated that the HP Technician on duty assumes HP Supervisor duties in an emergency until relieved by HP Supervision. The checklist also states that the shift HP Technician or an OSC Support Supervisor can temporarily assume the OSC Coordinator (OSCC) position until the on-call OSCC arrives.

The team determined that the shift HP Technician had specific emergency response functions as assigned by Emergency Plan Table 5-1. This person performed in-plant surveys, in-plant protective actions, and rescue/first aid. To assign him/her additional responsibilities in an Emergency Plan Implementing Instruction would not implement Table 5-1 as written. Additionally, the assignment of the shift HP Technician as interim OSCC, an augmented ERO responder, defeated the purpose of relieving the shift complement of duties so they appropriately respond to an emergency.

The team concluded that the potential assignment of the shift HP Technician as the interim OSCC did not comport with Emergency Plan Table 5-1 and therefore was not in compliance with the Emergency Plan. The assignment of additional duties to a Table 5-1 responder was viewed as a DIE of the Emergency Plan, which did not receive prior NRC approval.

Analysis: The team determined that the failure to obtain prior NRC approval for a changes to the Perry Emergency Plan concerning ERO staffing and response timeliness was a performance deficiency which warranted a significance evaluation. The Emergency Preparedness cornerstone was impacted by this issue.

Because the issue affected the NRC’s ability to perform its regulatory function, it was processed through the traditional enforcement process and evaluated using the SDP. Typically the severity level would be assigned after consideration of appropriate factors for the particular regulatory process violation in accordance with the NRC Enforcement Policy. The team determined that the finding was of more than minor significance since the finding was associated with the ERO readiness and procedure quality attributes of the Emergency Preparedness cornerstone and affected the cornerstone objective of ensuring that the licensee is capable of implementing adequate measures to protect the health and safety of the public in the event of a radiological emergency.

The finding was considered to be of only very low safety significance since the SM would make this decision in an emergency, and the assignment would only be for a short period of time until the on-call OSCC arrived.

Enforcement: Requirements of 10 CFR 50.54(q) states, in part, that a licensee authorized to possess and operate a nuclear power reactor shall follow and maintain in effect emergency plans which meet the standards in 10 CFR 50.47(b) and the requirements of 10 CFR 50, Appendix E, “Emergency Planning and Preparedness for Production and Utilization Facilities,” and the licensee may make changes to these plans without Commission approval only if the changes do not decrease the effectiveness of the plans. Contrary to this requirement, between May 2004 and the present, the licensee implemented changes to the Emergency Plan to allow the dual assignment of the shift HP Technician as the interim OSCC, which decreased the effectiveness of the Emergency Plan.

However, because of the very low safety significance of the issue and because the issue has been entered into the licensee's CAP, the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy **(NCV 05000440/ 2005003-26)**. This issue was entered into the licensee's CAP as CR 05-03271.

As part of the licensee's corrective actions, this issue was entered into the corrective action program for resolution.

5.2 Failure to Identify Impact of Security Plan Change on Emergency Plan

Introduction: A finding of very low safety significance (Green) and an associated NCV of 10 CFR 50.47(b)(4) was NRC-identified when a change was made that adversely impacted EAL implementation. Specifically, a Security Plan revision implemented on November 8, 2005, which eliminated terms from the Security Plan and Security Event Checklists adversely affected EAL event classifications.

Description: On November 8, 2004, the licensee revised its Security Plan and deleted terms from the Plan and Security Event Checklists that the Security Shift Supervisor (SSS) must communicate to the SM for two event classifications. Specifically, the revision deleted the terms "Security Alert" which was used in EAL NU1 for the declaration of a Notice of Unusual Event (NOUE), and "Security Emergency" which was used in EAL NA1 for the declaration of an Alert. Further, the licensee failed to identify that these changes would affect Emergency Plan EALs during the design bases impact review and the regulatory applicability determination performed for the Security Plan change.

The SM relied on the Security Shift Supervisor to use these terms during certain security events so that he could accurately classify the events in a timely manner. The terms were used in the two EALs as follows:

- NU1: Any security event resulting in the declaration of a SECURITY ALERT in accordance with the PNPP Physical Security Plan. (One of the two NOUE entry criteria)

- NA1: Any security event resulting in a declaration of a SECURITY EMERGENCY in accordance with the PNPP Physical Security Plan. (One of the two Alert entry criteria)

The deletion of these terms from the Physical Security Plan and the associated Security Event Checklists used by the Security Shift Supervisor for the mitigation of security events impacted the accuracy and/or timeliness of classifications under EALs NU1 and NA1.

Analysis: The team determined that the deletion of the terms "Security Alert" and "Security Emergency" from the Physical Security Plan without consideration of the impact on the Emergency Plan was a performance deficiency which warranted a significance evaluation. The Emergency Preparedness cornerstone was impacted by this issue. The team reviewed the samples of minor issues in IMC 06012, “Power Reactor Inspection Report,” Appendix E, “Examples of Minor Issues,” and determined that there were no examples similar to this issue. In accordance with Appendix B, “Issue Screening,” of IMC 0612, the team determined that the finding was of more than minor significance since the finding was associated with the ERO performance and procedure quality attributes of the Emergency Preparedness cornerstone and affected the cornerstone objective of ensuring that the licensee is capable of implementing adequate measures to protect the health and safety of the public in the event of a radiological emergency.

Using IMC 0609, “Significance Determination Process,” Appendix B, “Emergency Preparedness Significance Determination Process,” and Sheet 1, “Emergency Preparedness Significance Determination Process - Failure to Comply,” since the issue was the failure to comply with 10 CFR 50.47(b)(4) by not maintaining a standard scheme of emergency classification and action levels in use, the team determined that this finding:

- Involved a planning standard problem, since 10 CFR 50.47(b)(4) is 1 of the 16 Planning Standards;

- Involved a RSPS problem, since 10 CFR 50.47(b)(4) is one of the RSPSs;

- Did not result in a Planning Standard function failure since in accordance with Appendix B, Section 4.4, since this issue did not involve facility procedure changes which created conditions such that an existing EAL would not be declared for more than two Alerts. One Alert EAL was affected; and

- Did not result in a RSPS Degraded Function since in accordance with Appendix B, Section 4.4, the change did not affect more than one Alert.

Therefore, the finding was considered to be of only very low safety significance.

Enforcement: Requirements of 10 CFR 50.47(b)(4) are, in part, that a standard scheme of emergency classification and action levels be in use. Contrary to this requirement, on November 8, 2004, the licensee revised the Physical Security Plan and the associated Security Event Checklists, deleting two terms that were used in Emergency Plan EALs for classification of emergency events. Specifically, the term "Security Alert," used in EAL NU1, and "Security Emergency," used in EAL NA1, were deleted. This deficiency had the potential to cause an inaccurate event classification or to delay the SM's assessment of the entry criteria for EALs NU1 and NA1.

However, because of the very low safety significance of the issue and because the issue has been entered into the licensee’s CAP, the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (**NCV 05000440/ 2005003-27**). This issue was entered into the licensee's CAP as CR 03659.

As part of the licensee's immediate corrective actions, the licensee issued Security Operations Directive 05-0005 to require security personnel to use the terms "Security Alert" and "Security Emergency" when appropriate, to communicate event information to the SM. Additionally, the Operations Department issued an Operations Night Order dated April 21, 2005, which directed that SMs ask the Security Shift Supervisor if a Security Alert or Security Emergency was being declared.

6.0 Other Findings and/or NCVs

6.1 Failure to Identify a Maintenance Preventable Functional Failure (MPFF)

Introduction: A finding of very low safety significance (Green) and an associated NCV of 10 CFR 50.65(a)(1) associated with the requirements for monitoring the effectiveness of maintenance was identified when licensee personnel failed to establish appropriate goals and monitor the performance of the Division 2 EDG when the demonstration of effective control of performance of the EDG through appropriate preventive maintenance became invalid following a lube oil heat exchanger gasket failure.

Description: On November 13, 2000, during a post-maintenance test run of the Division 2 EDG, operators found water leaking from the right bank crankcase exhaust blower. The EDG was operating at approximately 5700 KW and was about to be loaded to 7000 KW at the time of discovery. As load was increased, crankcase vacuum began to decrease and the engine was secured without further incident. The vent line drain for the crankcase blower was drained and about 5 gallons of water was removed. In addition, about 1.5 quarts of water was drained from the right bank blower discharge. Evidence of water was also observed inside the valve covers. Inspections performed of the interior of the crankcase, the cylinder head/cover areas, the turbocharger oil drains, piston skirts, liners, main bearings, connecting rod bearings, and rocker arms showed no evidence of water or engine damage. The lubricating oil cooler shell side valve was opened and a significant quantity of water drained from this valve.

An engineering evaluation documented in CRs 00-3500 and 00-3561 determined that jacket cooling water had leaked into the lubricating oil side of the heat exchanger due to an incorrectly assembled lantern ring. The lantern ring is a "telltale" design, gasket joint, which should allow the leaking fluid to leak to the atmosphere rather than cross contaminating the other fluid (either the oil or jacket cooling water). The floating head type flange connection was designed to allow thermal expansion and contraction of the tube sheet during heat up and cooldown of the heat exchanger. Evidence of an incorrectly installed lantern ring included: 1) packing material extruded out of the packing box and over and under the lantern ring; 2) the leak ports in the lantern ring were clogged with a sealing material; and 3) the leak ports in the lantern ring were not aligned with the space shim gap. The engineering investigation concluded that this flange had been worked in April 1999, during RFO7, and that a gasket material change was made by the vendor, from asbestos to a neoprene rubber, without any changes to the installation procedures.

The maintenance rule evaluations performed for this condition were documented in CRs 00-3500 and 00-3561. Both reviews concluded that the condition was not a MPFF, since the jacket water leak occurred as a direct result of the in-progress maintenance activity. This conclusion was based on the licensee's belief that the improper lantern ring installation alone would not have caused the jacket water leak. The evaluation determined that the leak occurred due to a pre-existing condition that was revealed during the removal from service for maintenance when the engine was allowed to cool down during the scheduled EDG maintenance activities. While in this condition, the lubricating oil was drained from the shell side of the heat exchanger without jacket water being drained from the tube side. The evaluation also determined that this event did not constitute an engine failure as defined in Regulatory Guide 1.108, Revision 1, Position C.2.e and NUMARC 87-00, Revision 1, Appendix D.

The team consulted with NRC management and headquarters specialists regarding this issue. The team did not agree with the licensee's maintenance rule determination, since the failure was due to a latent condition introduced during an unrelated maintenance activity. In other words, the improper maintenance activity that resulted in the lantern ring failure was introduced in April 1999, and the maintenance activities performed in November 2000 did not directly involve the gasket/lantern ring joint. The affected joint was not disturbed during the maintenance activities for which the post-maintenance test was conducted; nor was there any consideration of any potential affect of the maintenance on this joint until conditions (i.e., several weeks of cold iron followed by heatup) allowed the latent leakage paths introduced by the mis-installed gasket to manifest themselves. The team believed that draining the oil from the shell side of the heat exchanger was not a direct result of the maintenance activity because a correctly installed gasket would not have allowed the observed leakage regardless of the normal thermal cycling and fluid draining associated with the extended maintenance period for which the post-maintenance test was conducted.

Since the initial evaluations of this condition identified in CRs 00-03500 and 00-03561 in December 2000 by the previous maintenance rule coordinator, the team interviewed the current maintenance rule coordinator and held several meetings to assess his evaluation regarding this issue. The maintenance rule coordinator determined that the initial evaluation was consistent with his understanding of the maintenance rule and that he would not consider this jacket water leak a MPFF for the same reasons presented in the initial evaluation. After several discussions with the system engineer, members of the licensee's IP 95003 Response Team, and the current maintenance rule coordinator, the team determined that the licensee had not properly categorized the Division 2 EDG jacket water leak as a MPFF.

Analysis: The team determined that the failure to establish appropriate goals and monitor the performance of the Division 2 EDG when the demonstration of effective control of performance or condition of the EDG through appropriate preventive maintenance as allowed by 10 CFR 50.65(a)(2) became invalid was a performance deficiency which warranted a significance evaluation. The Mitigating Systems cornerstone was impacted by this issue. The team reviewed the samples of minor issues in IMC 06012, "Power Reactor Inspection Report," Appendix E, "Examples of Minor Issues," and determined that there were no examples similar to this issue. In accordance with Appendix B, "Issue Screening," of IMC 0612, the team determined that the finding was of more than minor significance since the finding was associated with the equipment performance attribute of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

Using IMC 0609, “Significance Determination Process,” Appendix A, “User Guide for Determining the Significance of Reactor Inspection Findings for At-Power Situations,” and “SDP Phase 1 Screening Worksheet for Initiating Events, Mitigating Systems, and Barriers Cornerstones,” the team determined that this finding 1) was not a design deficiency or qualification deficiency ; 2) did not represent an actual loss of safety function of a system; 3) did not represent an actual loss of safety function of a single train for greater than its TS allowed outage time; 4) did not represent an actual loss of safety function of one or more non-TS trains of equipment designated as risk significant; and 5) did not screen as potentially risk significant due to seismic, flooding, or a severe weather initiating event. Therefore, the finding screened as Green and was considered to be of only very low safety significance.

Enforcement: As specified in paragraph (a)(1) of 10 CFR 50.65(a)(2) monitoring is not required where it has been demonstrated that the performance of condition of an SSC is being effectively controlled through the performance of appropriate preventive maintenance, such that the SSC remains capable of performing its intended function. Contrary to this requirement, as a result of a failure to properly account for all MPFFs, the licensee no longer demonstrated effective control of the performance of the EDG, yet failed to establish goals and monitor EDG performance as required by paragraph 10CFR 50.65(a)(1).

However, because of the very low safety significance of the issue and because the issue has been entered into the licensee’s CAP, the issue is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy (**NCV 05000440/ 2005003-28)**. This issue was entered into the licensee’s CAP as CR 05-04114.

As part of the licensee’s corrective actions, licensee personnel planned to discuss this issue with industry peers and determine whether the criteria used to categorize this event as a Maintenance Preventable Functional Failure was consistently understood and accepted.

ATTACHMENT 2

PERRY PERFORMANCE IMPROVEMENT INITIATIVE REVIEW

4.0 Perry PII Review

4.1 Background

By letter dated September 30, 2004, FirstEnergy advised the NRC that prior to receiving the NRC's August 12, 2004, Assessment Followup Letter in which the PNPP was identified to have transitioned into the Multiple/Repetitive Degraded Cornerstone column of the NRC's Action Matrix, actions were underway to improve plant performance. To facilitate these performance improvements, FirstEnergy developed the Perry PII. This improvement initiative was formed using insights from NRC Inspection Procedure 95003, lessons learned from the Davis-Besse Nuclear Power Station, and lessons learned from other stations that were placed under the IP 95003 inspection process. As detailed in the licensee's September 30, 2004, letter, to correct the identified declining trends in performance at Perry, the PII was structured around the following six key improvement initiatives:

- Equipment Performance and Configuration;
- Program/Procedure Review;
- Containment and Safety Systems;
- Corrective Action Implementation Improvement;
- Organizational Effectiveness Improvement; and
- Validations of Root Cause Actions and Effectiveness Review of Root Cause Corrective Actions.

To direct the implementation of the PII, a Detailed Action & Monitoring Plan was developed by the FirstEnergy Executive Leadership Team.

As part of this IP 95003 inspection, the team conducted a detailed review of the Perry PII. This review consisted of two parts. The first part of the inspection consisted of a review of the scope of the PII and determined whether the PII, if implemented as written, could achieve the overall goal of correcting the declining trends of performance at Perry. The second part of the review consisted of an inspection of selected actions prescribed in the PII Detailed Action & Monitoring Plan. These reviews were completed with the following results.

4.2 PII - Scope Review

4.2.1 Background

To correct the identified declining trends in performance at Perry, the Perry PII was structured around the following six key improvement initiatives:

Equipment Performance and Configuration

The Equipment Performance and Configuration Initiative Plan provided for reviews of system health to enhance safe and reliable plant operation. The initiative also included improvement actions relative to fuel reliability and critical calculations. Two levels of system reviews were identified. The first level of review provided for a System Health Review (SHR) on selected Maintenance Rule and TS systems. In addition, a number of Latent Issue Reviews were planned.

Program/Procedure Review

The Program/Procedure Review Initiative provided for a review of selected plant programs to ensure that the programs were fulfilling required commitments and continued to support safe operation at the PNPP. The list of programs assessed was developed through a review of significant CRs, NRC inspection reports, Institute for Nuclear Power Operation (INPO) evaluations, QA assessments, Company Nuclear Review Board reports, other self-assessments, key attributes from IP 95003, and the list of programs selected as part of the Davis-Besse Restart Plan.

Containment and Safety Systems

The Containment and Safety System Initiative was designed to improve the material condition of the containment and strengthen the systems to mitigate events. The plan also initiated assessments and monitoring strategies to strengthen the organizational focus on equipment reliability.

CAP Implementation Improvement Initiative

As detailed in the PII, several program compliance and program implementation failures were identified in Root Cause Reports, including inadequate implementation of the CAP. The CAP Implementation Improvement Initiative was designed to address the CAP implementation issues that have been identified. As discussed in the CAP Implementation Improvement Initiative, this initiative was designed to improve the overall health of CAP implementation. This was intended to be accomplished through interim actions to affect immediate improvement and longer term actions designed to ensure sustained improvement for all critical attributes of the CAP. Initially, the primary focus of the improvement initiative was in three areas; skill improvement of investigators, improved monitoring and oversight of CAP health, and improvement in the effectiveness of corrective action implementation (both timeliness and taking effective action to resolve the issue). A Corrective Action Board was formed using industry expertise, to oversee the completion of improvement actions as well as to continuously assess CAP implementation.

Organizational Effectiveness Improvement

The Organizational Effectiveness Improvement Initiative was developed to initiate a substantive and demonstrative change in the organizational effectiveness at Perry.

Validations of Root Cause Actions and Effectiveness Review of Root Cause Corrective Actions

The Validation of Root Cause Actions and Effectiveness Review and Root Cause Corrective Actions Initiative was designed to ensure that actions identified and implemented to resolve root cause events were effective.

4.2.2 PII - Scope Review Results

a. Inspection Scope

The team independently reviewed the results of recently completed major assessments and NRC activities conducted at Perry, evaluated whether or not the problems identified in those assessments had been corrected, and determined if the actions in the PII addressed the problems that still existed at Perry. The following major assessments were reviewed by the team:

- Common Cause Analysis Report and Organizational Effectiveness Improvement Initiative, Revision 2 - Condition Report 03-05995;
- Root Cause Report 02-03972, Revision 4 - HPCS Pump Failure to Start;
- Root Cause Report 03-04764, Revision 1 - Low Pressure Core Spray/Residual Heat Removal Waterleg Pump Air Binding;
- Root Cause Report 03-04912, Revision 1 - Division 1 Emergency Diesel Generator Inoperable During Mode Change;
- Root Cause Report 03-05065, Revision 1 - Emergency Service Water Pump Coupling Failure;
- Root Cause Report 04-02598, Revision 0 - ESW Pump Coupling Repeat Failure;
- Refueling and Forced Outage Critiques; and
- Quality Assurance Assessment Reports

b. Observations and Findings

The PII process was implemented through the following procedures:

- PYBP-PII-0001, PII;
- PYBP-PII-0002, PII Detailed Action & Monitoring Plan;
- PYBP-PII-0003, PII Program Review Process;
- PYBP-PII-0004, Perry Performance Overview Panel Charter; and
- PYBP-PII-0005, Perry Closure and Validation of PII Actions

Each initiative of the PII was composed of Action Plans to address improvement areas. The Action Plans were categorized by PII area, and their status was tracked in the Perry Business Plan PII procedure PYBP-PII-0002, "Detailed Action & Monitoring Plan." Each Action Plan was composed of Action Items with corresponding due dates.

The team focused primarily on the content of licensee reviews such as program and procedure reviews. However, since these reviews were only recently completed by the licensee, corrective actions were not formulated and not reviewed by the team. The licensee had also not completed more significant reviews in areas such as procedure quality and human performance. The team identified that some programs such as Operating Experience, ODs, and Containment Labeling and Coating were being effectively addressed; however, the Work Control program contained a relatively large backlog of surveillances and planned maintenance activities. The team identified that reviews stated the program was acceptable, but identified a majority of the key areas as inadequate.

The PII continued to emerge and grow as programs were increased in scope and additional programs are added. The PII started with 242 items and 20 programs, and expanded to 274 items and 23 programs. The Organizational Effectiveness section of the PII had also been recently revised and added Station Alignment, Safety Culture, Operations Improvement, and Human Performance sections. Significant portions of the CAP were also recently added and included Effective Cause Evaluation, Problem Identification, Trending, and Screening.

Following a review of the scoping of the Perry PII, the team concluded that the PII had a broad scope and addressed many important performance areas. The team also observed that although substantially completed, the PII had not yielded significant improvement in plant performance in many areas. Some of the reasons why this has occurred included the following:

Dependency on CAP

The PII consisted of a systematic process for addressing issues that included the development, approval, implementation, validation, and closure of corrective actions. Once implemented, the effectiveness of the corrective actions were required to be evaluated for further action if necessary. The problems identified in the PII reviews depended upon the proper implementation of the CAP to address issues. During this inspection, the team identified that in some cases the CAP had not been implemented adequately to address the concerns identified during PII reviews. The team also observed that although PII items may be closed, the corrective actions to address the identified problems may not have been identified or implemented.

Discovery Aspects of the PII

Another important factor was that the PII was largely a discovery activity and as such many elements of the PII did not directly support improving plant performance.

The team also identified that a significant number of the completed Detailed Action & Monitoring Plan Action Plan items, although necessary, appeared to be of only minimal direct benefit because they involved reviews with no assessment, or did not specifically correct an identified problem. On May 21, 2005, the team reviewed the updated Detailed Action & Monitoring Plan and identified that 66 Action Plan items were approved in final. The team identified that 24 of the 66 items were of minimal immediate benefit because they focused in the following areas:

- Items for review with no assessment or evaluation;
- Identification of a program owner;
- Scheduling of an item for review;

- Development of metrics or PIs;
- Development of lists;
- Periodic status updates; and
- Continuation of meetings.

Implementation of PII Relatively Slow

The team also identified that a number of extensions has slowed the implementation of the PII. Extensions were proposed at owner/sponsor meetings and were approved per program requirements. The team reviewed Detailed Action & Monitoring Plan Revisions 0 through 3 to obtain the revised due dates. The team identified that 115 of 274 items (42 percent) had extended due dates that averaged over 60 total days per item. The team identified that 22 of 66 items categorized as completed (33 percent) and 36 of 81 items categorized as pending (44 percent) exceeded their respective due dates. Based on the number of items with extensions, the average length of extensions, and the items exceeding their due dates, the team had little confidence in the licensee's identified completion schedule.

4.3 PII - Implementation Review

4.3.1 Equipment Performance and Configuration Plan

a. Inspection Scope

The team reviewed the implementation of the Equipment Performance and Configuration Initiative Plan, Revision 2, dated January 6, 2005. In particular, the team reviewed the following key action items prescribed in the Detailed Action & Monitoring Plan, Revision 3, dated April 4, 2005:

- Key Action 1.2 - Complete three SHRs on the selected systems

- Key Action 2.2 - Complete the Division 1 and Division 2 EDG Latent Issue Review

- Key Action 2.3.1 - Cumulative assessment of the results of the completed Latent Issues Reviews to determine the scope/approach of future reviews

Key Action 1.2: Complete three SHRs on the selected systems

As detailed in the Equipment Performance and Configuration Initiative Plan, the Perry review team conducted SHRs using approaches including:

- Review the "Collective Significance/Common Cause of Safety and Mitigating System Failures" Condition Report, 03-05995, and the repeated equipment problems Condition Report 03-06470, "Organizational Behavior Issue Results in Untimely Resolution of Equipment Issues," to assist in defining focus areas for review.

- Define the risk-significant system functions.

- Review the Critical Component list for the system and identify critical components.

- Review the tests or activities that demonstrate how each risk-significant function is tested or assessed.

- Review Preventative and Predictive Maintenance performed on critical components.

- Assess the system health with particular focus on critical components.

- Interview Operations personnel for their opinion on how the system/components are performing.

During this inspection, the team reviewed the licensee's SHR associated with the SLC system, RPS, and the Control Rod Drive Hydraulic (CRDH) system.

<u>Key Action 2.2</u>: Division 1 and Division 2 EDG Latent Issues Review

The Latent Issues Project was drafted to perform an in-depth review of selected systems and components from a design, operation, maintenance, and testing perspective.

As discussed in the Equipment Performance and Configuration Initiative Plan, a team approach was utilized for the Latent Issues Review. The Latent Issues Review is a more comprehensive review of a system and includes items above and beyond the System Health review such as:

- Verify the adequacy of the pre-operational test against the design of the system.
- Validate maintenance (including maintenance practices and procedures) and continuing testing (post-modification testing, post-maintenance testing, periodic, and SVIs) is adequate to provide reasonable assurance that the original design capabilities and licensing requirements are maintained.
- Verify the configuration of the system(s) matches design and licensing basis and configuration control programs are in place to maintain configuration (As-built program and Modification process).
- Verify modifications meet original design and licensing basis or changes have been adequately assessed, codes and standards continue to be met, and design changes were adequately tested.
- Verify the adequacy of engineering programs designed to detect system(s) degradation (i.e. Flow Accelerated Corrosion (FAC), In-Service Inspection/In-Service Testing, (ISI/IST)).
- Review applicable industry operating experience.

During this inspection, the team reviewed the licensee's Latent Issue Review associated with the Division 1 and Division 2 EDGs.

Key Action 2.3.1: Latent Issues Reviews Cumulative Assessment

Cumulative assessments of the results of the Latent Issues Reviews were planned to determine the scope and approach of future reviews. Two issues were identified to be addressed when performing these reviews. First, the cumulative assessment will evaluate the results of a series of Latent Issues Reviews to determine if the scope of future reviews should be changed to focus on common issue themes that have been identified.

Second, a primary function of the Latent Issues Review was to identify new or unknown issues. The cumulative assessment will be used to determine if the primary focus of future reviews should continue to be on identifying new issues or, if the focus of the reviews should be more directed toward taking action to resolve already known issues.

During this inspection, the team reviewed the Latent Issues Reviews Cumulative Assessment.

b. Observations and Findings

Key Action 1.2: Complete three SHRs on the selected systems

The team reviewed the closure documentation for this item which included the SHRs for the SLC system, RPS, and CRDH system. Each SHR documented a review of surveillance tests, preventive maintenance, open CRs and corrective actions, open modifications, operating experience, historical problems, and maintenance history. These reviews resulted in a colored overall system health rating.

The SLC system health was determined to be acceptable and was rated Green (excellent) in both the material condition and operational focus areas with eight CRs generated as a result of the SHR. The team did not identify any significant concerns with the SLC SHR itself. Two of the CRs generated during the SLC SHR were associated with a SCAQ which was previously unrecognized by the licensee. However, as detailed in Attachment 1 of this report, licensee personnel failed to adequately address concerns identified during the SLC SHR regarding SLC relief valve setpoints in an MSIV closure/ATWS initiating event.

The RPS health was also determined to be acceptable and rated White (acceptable) in Overall Performance; Green (excellent) in Nuclear Safety; White (acceptable) in Material Condition; and White (acceptable) in Operational Focus with 10 CRs being generated as a result of the SHR. The team did not identify any significant concerns with the RPS SHR.

The CRDH system health was determined to be acceptable and rated Yellow (needs improvement) in Overall Performance; Yellow (needs improvement) in Nuclear Safety; Red (not acceptable) in Material Condition; and Yellow (needs improvement) in Operational Focus; with 18 CRs being generated as a result of the SHR. The SHR identified two significant issues which were entered into the CAP. The team did not identify any significant concerns with the CRDH SHR itself, however, a plant walkdown by the team identified an issue that was not previously recognized by the licensee when directional control valve identification tags attached to the HCU solenoid valve cable potentially interfered with the position indication limit switch operation for the scram valve.

Key Action 2.2: Division 1 and Division 2 EDG Latent Issues Review

The team reviewed the closure documentation for this item which included a copy of the latent issues review. This review encompassed preventive maintenance activities, surveillance testing, component and integration testing, maintenance history, operating experience, and a review of the design bases. The review graded the EDGs as Yellow (needs improvement) and identified a large number of issues. There were 80 CRs initiated as a results of this review. The team did not identify any issues beyond those already identified by the licensee, however one of the CRs was not adequately dispositioned as discussed in Attachment 1 of this report.

Key Action 2.3.1: Latent Issues Reviews Cumulative Assessment

The team reviewed licensee Self-Assessment 755PII2005, “Cumulative Assessment of the Latent Issues Reviews and System Health Reviews Performed at the PNPP.” This self-assessment appeared to critically review the SHRs for the SLC system and the CRDH System, and the Latent Issues Reviews for the ESW, ECCW and the EDGs. Two “Areas For Improvement” (AFIs) were generated and documented in CRs. These involved Ineffective Use of the Corrective Action Process (CR 05-01221) and Engineering Rigor (CR 05-01223). Two other CRs were generated concerning improvements in the SHR and Operating Experience processes.

The team did not identify any new issues as a result of this review. The team agreed with the licensee’s conclusion that there was room for improvement in the resolution of issues and engineering rigor as was evidenced by the results of this inspection.

4.3.2 Program/Procedure Review Initiative

a. Inspection Scope

The team reviewed the implementation of the Program/Procedure Review Initiative, Revision 1, dated November 16, 2004. In particular, the team reviewed the following key action items prescribed in the Detailed Action & Monitoring Plan, Revision 3, dated April 4, 2005:

Program-Related Activities

- Key Action 1.1 - Perform a review of the Configuration Management Program
- Key Action 1.1.1 - Evaluate the Configuration Management Program Review Package and implement any remedial actions required to ensure the program will support safe operation
- Key Action 1.6 - Perform a review of the On-line Risk Management Program

- Key Action 1.6.1 - Evaluate the On-line Risk Management Program Review Package and implement any remedial actions required to ensure the program will support safe operation

- Key Action 1.7 - Perform a review of the OD Program

- Key Action 1.7.1 - Evaluate the OD Program Review Package and implement any remedial actions required to ensure the program will support safe operation

- Key Action 1.11 - Perform a review of the Emergency Preparedness Program

- Key Action 1.11.1 - Evaluate the Emergency Preparedness Program Review Package and implement any remedial actions required to ensure the program will support safe operation

As discussed in the PII, the Program/Procedure Review Initiative was developed to ensure that the applicable programs were in a condition to support the safe operation of Perry and the actions from this initiative would strengthen the program and procedures barrier. As such, the reviews encompassed the following:

Standards

- The program attributes comply with the requirements of the applicable basis documents and commitments;
- The program attributes incorporate a measure of industry best practices above the minimum standards;

Ownership

- The program goals and scope are appropriate;
- The program owner is properly qualified;
- Interfaces and handoffs with other programs or work groups are positively controlled and effectively implemented;
- The program appropriately incorporates operating experience;

Oversight

- The program has an appropriate level of management involvement;
- The program PIs are appropriately selected and periodically reviewed by management; and
- The roles and responsibilities for program implementation are clearly defined and appropriately implemented.

During this inspection, the team reviewed a sample of the licensee's assessments of a number of programs, including the actions developed to address identified issues, and determined whether these assessments appeared to be effectively accomplished and corrective actions appeared to be appropriate.

Procedure-Related Activities

- Key Action 2.1.2 - Incorporate "Use Category" and incorporate the level of use into any procedure changes resulting from the maintenance procedure content assessment (CA-03-05995-05)

Corrective actions associated with CR 03-05995-05 prescribed that MAI-0501, "Preparation and Formatting of Maintenance Instructions," be revised to consider the appropriate level and incorporate the "Level of Use" into new procedures.

- Key Action 2.2.1 - Develop a maintenance procedure upgrade plan for key critical components

This item prescribed that a plan be developed to upgrade maintenance procedures associated with critical system components in a manner that considered the relative risk- and safety-significance of the affected equipment.

- Key Action 2.2.2 - Develop the list of maintenance procedures for key critical components using probabilistic safety assessment (PSA) insights

As discussed in the Program/Procedure Review Initiative, the licensee's investigation of recent operational events questioned the technical adequacy of procedures used to maintain critical plant components and recommended a project to upgrade maintenance procedures to conform to industry best practices. The recommendation included upgrading the formatting of all the maintenance procedures to a fleet standard, incorporating human factor engineering to reduce errors and eliminate human error traps, and the validation of the technical accuracy and usability of the procedures. This initiative was intended to represent an initial phase of this project by performing a review of maintenance procedures associated with selected key critical components. The goal of the review of the selected maintenance procedures was to provide:

- Complete and accurate procedures that include appropriate technical depth and information, and

- Identification of critical steps and appropriate human performance barriers for these steps.

During this inspection, the team reviewed a number of key action items intended to address the overall goal of improving the quality of procedures and determined whether these corrective actions were effectively implemented.

b. Observations and Findings

Program-Related Activities

Key Actions 1.1 and 1.1.1: Configuration Management Program

The team reviewed the licensee's evaluation of the configuration control program and plant procedures for configuration control. The PII evaluation concluded that the program supported safe operation. The team noted that the licensee's assessment identified the primary concern of the configuration control program as an "ongoing human performance problem with implementation of the individual programs." Corrective actions to address the human performance issues included training and several procedural revisions. The PII evaluation also identified that the lack of an integrated configuration control procedure deviated from the baseline attributes. The team noted that a FENOC procedure was being developed to establish an integrated configuration management program. The PII assessment team also identified some procedural weaknesses which were characterized as minor. The team noted that the corrective actions for this Key Action were pending. Recent procedural adherence issues have been addressed by plant management, but knowledge deficiencies have not been programmatically addressed. The PII assessment lacked depth in that no root cause had been identified for the primary concern of the lack of procedural and program adherence. Given the cumulative significance of the historical configuration control issues at Perry, a root cause investigation was warranted and was recently initiated.

Key Action 1.6 and 1.6.1: On-line Risk Management Review

The team reviewed the licensee's assessment of the On-line Risk Management Program. In discussions with the licensee's PRA analysts, the team determined that the on-line risk program had not been updated after the PRA was updated in April 2004. The last update to the on-line risk program was performed in 2002. The team determined that no significant plant changes had occurred since the last update and, as a result, the on-line risk program would continue to reasonably reflect the actual plant configuration. The licensee's PRA staff informed the team that an update to the program was planned for the end of 2005; however, the team noted that the update was not included in the licensee's PII for the on-line risk program.

Key Action 1.7 and 1.7.1: Operability Determination (OD) Program Review

The team reviewed OD guidance in licensee procedures PAP-0205 and PYBP-SITE-0014, outstanding operability evaluations for the RHR and EDG systems, and the PII assessment. The PII assessment identified procedural weaknesses, a lack of technical rigor, insufficient management oversight, and inadequate review/ownership by the Operations Department as contributing to the OD program weaknesses. All of these issues were addressed in the PII review and had been assigned corrective actions. Corrective actions included procedural changes, improved training, and improved management tracking. The team concluded that, if implemented correctly, these corrective actions should improve the licensee's OD program. The current OD program will support safe operation.

Key Action 1.11 and 1.11.1: Emergency Preparedness Program Review

The team reviewed the Emergency Preparedness portion of the licensee's PII. This initiative was broad in scope and focused on the areas of human performance, equipment performance, facility readiness, and procedure quality. The team concluded that the licensee's effort was instrumental in identifying key issues warranting improvement, including drill/exercise performance issues and EAL changes that decreased the effectiveness of the Emergency Plan. However, the team also noted some deficiencies which had not been identified and corrected. These included:

- Inadequate safety evaluations (i.e., 10 CFR 50.59 safety reviews) which resulted in some Emergency Plan and Implementing Instruction changes that decreased the effectiveness of the Emergency Plan.

- Several CRs for EAL format and/or content issues that were written at a threshold which required no apparent or root cause determination to investigate the causal factors for deficiencies.

- Detailed EAL reviews failed to identify a Security Plan change which impacted two security-related EALs.

These issues could have been identified during the licensee's improvement activities and were not. However, the team concluded that, overall, the Emergency Preparedness program was adequate.

Procedure-Related Activities

Key Action 2.1.2: Incorporate "Use Category" and Level of Use in Maintenance Procedure Changes

Corrective actions associated with CR 03-05995-05 incorporated this requirement into MAI-0501, "Preparation and Formatting of Maintenance Instructions," which directed that this action consider the appropriate level and incorporate the "Level of Use" into new procedures. This action was assigned by the CR on February 26, 2004. This revision along with other revisions was completed on May 7, 2004. This was considered an appropriate improvement to maintenance procedures and was completed in a reasonable time. No deficiencies were identified.

Key Action 2.2.1: Develop Maintenance Procedure Upgrade Plan

The licensee developed a risk-based calculation to prioritize which maintenance procedures were critical and should be immediately upgraded. The plan originally identified 107 procedures for upgrading. Thirteen additional procedures were added after the initial 107 were identified. The method of selecting the priority of procedures for upgrading was reasonable. An independent check of the list of prioritized procedures reflected what would be expected for a PRA-based analysis and reflected recent maintenance issues. Milestone activities and due dates were also established as a part of the upgrade plan. The due dates assigned were reasonable. No deficiencies were identified.

Key Action 2.2.2: Develop the List of Maintenance Procedures for Key Components

This action item required creation of the list generated from PII Key Action 2.2.1 which initiated the review and incorporation of improvements into the 120 selected maintenance procedures. Of note was that the maintenance department had more than

1200 procedures that had not been upgraded. Continued management focus was warranted to ensure that maintenance procedures as well as other critical plant procedures acted as a barrier to human errors. No deficiencies were identified.

4.3.3 Containment and Safety Systems Plan

a. Inspection Scope

The team reviewed the implementation of the Containment and Safety System Initiative, Revision 1, dated October 14, 2004. In particular, the team reviewed the following key action items prescribed in the Detailed Action & Monitoring Plan, Revision 3, dated April 4, 2005:

- Key Action 1.3 - Develop the Containment component/equipment Labeling Improvement Project plan

- Key Action 6 - Develop and implement a Safety System Unavailability (SSU) Improvement Plan

- Key Action 13.1 - Implement actions necessary to remove the EDG vibration switches to improve system reliability (Engineering Change Request (ECR)-04-0092; ECR 04-0092-A)

- Key Action 13.2 - Implement actions necessary to install Testable Rupture Discs in the EDG exhaust system (CA 03-06691-01)

Key Action 1.3: Develop Containment Labeling Improvement Project Plan

The team reviewed the licensee's initiative to improve the inside containment component/equipment labeling program. This initiative is one of three parts of the Containment and Safety Systems Initiative to improve the overall material condition of the containment and strengthen the systems designed to mitigate events.

Key Action 6: Develop Safety System Unavailability (SSU) Improvement Plan

As detailed in the Containment and Safety System Initiative, the purpose of the Safety SSU Improvement Plan was to drive improvement of the SSU at Perry. The Plan used a multifaceted approach to reduce SSU by minimizing out of service time and improving divisional outage performance.

Key Action 13.1: Remove EDG Vibration Switches to Improve EDG Reliability

As discussed in ECP 04-0092, vibration switches associated with the Division 1 and Division 2 EDGs were removed to eliminate a potential failure mode from the EDG system.

The team reviewed this modification and determined whether the design change adversely impacted the ability of the system to perform its design basis function and determined whether the change would result in an undesired initiating event. During this review, the team evaluated the effectiveness of the licensee in controlling design and licensing information, and in developing and implementing thorough post-modification testing. The team assessed the adequacy of the licensee in evaluating applicable system and support system design attributes and regulatory requirements. The team also ensured that the original design and accident analyses assumptions were not invalidated by the changes. Additionally, the team reviewed the modification to confirm that the licensee had properly evaluated any required changes or additions to plant procedures.

Key Action 13.2: Install Testable Rupture Discs in EDG Exhaust System

As part of the PII, the licensee determined to resolve long-standing issues with the reliability of EDG TRDs. The TRD provide a means to allow the EDG to exhaust in the event the downstream muffler becomes restricted; for example during a tornado or seismic event. The licensee developed a design to allow the EDG to exhaust into the protective missile shield that incorporated addition of insulation to the missile shield and portions of the exhaust piping.

b. Observations and Findings

Key Action 1.3: Develop Containment Labeling Improvement Project Plan

The team reviewed the licensee's initiative to improve containment component and equipment labeling. Although, actual implementation of this initiative had not begun at the end of this inspection, the team concluded that the proposed actions appeared to be adequate to improve the overall material condition inside containment. No deficiencies were identified.

Key Action 6: Develop SSU Improvement Plan

The team reviewed the PII plan to reduce SSU and interviewed cognizant licensee personnel. The PII plan to integrate preventative and corrective maintenance to reduce SSU had been established. This plan utilized scheduled safety system outages for planned maintenance and more efficient grouping of maintenance activities. No deficiencies were identified.

Key Action 13.1: Remove EDG Vibration Switches to Improve EDG Reliability

The team reviewed the ECP, drawings, procedures, and modification WO, and performed walkdowns to assess whether the design intent had been adequately implemented. In addition, the team reviewed the PII closure and validation records to assess the effectiveness of the PII reviews.

The team did not identify any significant concerns, however, the team identified several minor issues that were not previously recognized by the licensee. In addition, the team concluded that the PII Closure and Validation Review was used as a simple tracking mechanism, with no critical review for the effectiveness of the modification's implementation. Specifically, the team noted three key validation review attributes, associated with implementation, that the PII Review did not perform (i.e., attribute item was marked not applicable):

- Implementing procedures followed, acceptance criteria defined and satisfied
- Identified deficiencies are documented for resolution
- QA oversight results considered

The team noted that the PII validation review attributes which were not performed, were in the areas where the team had identified several minor issues. The team concluded that the PII validation review was not fully effective in identifying design control and implementation problems, which appeared to be indicative of weaknesses in attention-to-detail.

The team identified several minor configuration control issues that were previously unrecognized by licensee personnel. The licensee entered these issues into their CAP as CRs 05-03103, 05-03108, and 05-03111. The issues included:

- The design function for R43-F500A changed from a normally open instrument root valve to a normally closed pressure boundary isolation valve for the EDG pneumatic trip system. The ECP required that R43-F500A be closed and tagged "Do Not Open." The team found R43-F500A closed, but not tagged as required.

- Drawing 302-0349 was updated differently than indicated on the approved IDCN, such that R43-F500B was incorrectly labeled as abandoned.

- There were component nomenclature differences (i.e., labeling) between the Division 1 and Division 2 drawings.

- The ECP required R43-F500A be administratively controlled closed. The Affected Documents List identified IMI-E04-08, "I&C Valve Line-up Instructions," as requiring revision. The team identified that the valve line-up procedure had not been revised, and no revision request was pending.

- The Division 1 EDG control room and local alarm response procedures (ARI-H13-P877-0001-F2 and ARI-H51-P054A) had not been revised although 6 months had elapsed following work completion. However, the Division 2 EDG procedures had been revised. The Division 1 EDG procedure change requests were prioritized as "Category 6 - Activities that can be deferred indefinitely or are associated with DCPs."

<u>Key Action 13.2</u>: Install Testable Rupture Discs in EDG Exhaust System

The team determined that licensee personnel adequately resolved this issue. However, during the modification effort, the following issues were identified that were indicative of problems in the areas of design control, procedure adherence, and CAP implementation:

- During this inspection and as detailed in Attachment 1 of this report, licensee personnel failed to adequately evaluate the effect of water intrusion on the insulation composite installed in the EDG exhaust enclosure.

- During this inspection and as detailed in Attachment 1 of this report, the team identified that licensee personnel inappropriately considered the ARC design procedure, NOP-CC-2003, to be satisfied through "intent" although the EDG missile barrier was not considered out-of-service as required by NOP-CC-2003 while the missile barrier was in the process of being modified.

- During this inspection and as detailed in Attachment 1 of this report, the team identified that licensee personnel failed to adhere to the At-Risk-Change procedure used for the modification of safety-related equipment. As a result, the configuration of the Division 1, 2, and 3 EDGs was not properly controlled and insulation was inappropriately hung on the EDG exhaust missile shield and ventilation exhaust piping without considering the EDGs to be inoperable.

4.3.4 <u>CAP Implementation Improvement Initiative</u>

a. <u>Inspection Scope</u>

The team reviewed the implementation of the CAP Implementation Improvement Initiative, Revision 1, dated December 29, 2004. In particular, the team reviewed the following key action items prescribed in the Detailed Action & Monitoring Plan, Revision 3, dated April 4, 2005:

- Key Action 1.16 - Revise PYBP-PIU-002 (04-02404-01)

- Key Action 1.17 - Develop a method to sample and grade OE evaluations to ensure procedural compliance is maintained (04-02404-02)

- Key Action 5.4 - Perform an aggregate review of the outstanding ODs to ensure the total population impact is evaluated as a total in addition to the previous evaluations performed individually (04-02468-60)

<u>Key Action 1.16</u>: Revise PYBP-PIU-002

The purpose of this key action item was to revise PYBP-PIU-002 such that the format was changed from reference guide to implementing procedure, thorough screening and evaluation criteria were included, subject matter experts were involved in the operating experience screening process, and multiple evaluations could be performed for applicable operating experience with multiple causes and contributing causes.

During this inspection, the team reviewed the revised procedure to determine whether all of the intended changes had been accomplished.

Key Action 1.17: Develop Method to Sample and Grade OE Evaluations

The purpose of this key action item was to develop a method to sample and grade operating experience evaluations to ensure procedural compliance was maintained.

During this inspection, the team reviewed the licensee's process for the review of operating experience evaluations to determine whether that process, if implemented as designed, would provide for effective operating experience reviews.

Key Action 5.4: Aggregate Review of Outstanding ODs

The purpose of this key action item was to perform an aggregate review of the outstanding ODs to ensure the total impact, in addition to the individual impact, was evaluated.

During this inspection, the team reviewed the licensee's assessment of the ODs , independently assessed the impact of the ODs, and compared the results.

b. Observations and Findings

Key Action 1.16: Revise PYBP-PIU-002

The team reviewed FENOC procedure NOP-LP-2100 for operability evaluation programs, which replaced the Perry site-specific procedure. The team verified that the new procedure incorporated the desired attributes. No deficiencies were identified.

Key Action 1.17: Develop Method to Sample and Grade Operability Evaluations

The team reviewed the OE grading criteria, interviewed the OE program coordinator, and reviewed monthly OE evaluation results from May 2004 to February 2005. The team noted that although some OEs required rework, corrective actions were only limited to re-performing the OE evaluation rather than addressing the underlying cause of poor evaluations. The team also noted that graded reports indicated an improving trend and that the OE program coordinators were reviewing OE documentation over a 2 year period when the OE evaluations were susceptible to programmatic weaknesses.

Key Action 5.4: Aggregate Review of Outstanding ODs

The team reviewed the aggregate OD evaluation documented in CR 04-02468 for outstanding ODs as of November 2004. The licensee evaluated the cumulative effect of ODs for which the SSC had been declared operable with outstanding corrective actions using their probabilistic safety assessment model. The team reviewed the cumulative assessment. No deficiencies were identified.

4.3.5 Organizational Effectiveness Improvement Plan

a. Inspection Scope

The team reviewed the implementation of the Organizational Effectiveness Improvement Initiative, Revision 0, dated December 29, 2004. In particular, the team reviewed the following key action item prescribed in the Detailed Action & Monitoring Plan, Revision 3, dated April 4, 2005:

- Key Action 6.3 - Develop and approve the Training Improvement Plan

Key Action 6.3: Develop Training Improvement Plan

The PII Detailed Action & Monitoring Plan identified the action to develop and approve the Training Improvement Plan. The Training Improvement Plan was implemented to improve the overall effectiveness of the licensee's Training Program. The primary focus of the initiative was to elevate the licensee's use of training to improve individual and plant performance. The bases of the program was a result of the INPO Technical Training Program Accreditation Team visit conducted from October 25 to October 29, 2004, which identified three findings and re-opened an additional licensee-identified finding. The licensee documented the findings in CR 04-06111 and formed a Root Cause Team to examine the issues and extent of condition to determine the depth and breadth of the problems. In parallel, a Transformational Team of line and training individuals was formed in November 2004 to assist in transforming the licensee's training programs and identifying corrective measures. The team included the Beaver Valley training manager and supervisors. The results from the Root Cause Team and Transformational Team were merged to form the bases for the Training Improvement Initiative. The Root Cause Team identified three root causes and two contributing causes:

Root Causes:

- Management did not create an appropriate culture and establish expectations to foster an environment that encouraged the use of training to improve plant performance.

- Inadequate oversight by plant management was reflected by a lack of rigor in followup of corrective actions and implementation of self-assessments.

- The corrective action process was not used effectively to support the identification, tracking, and resolution of training issues.

Contributing Causes:

- Existing procedures and administrative controls were not detailed enough to prevent declining performance in training.

- Line and training management did not effectively prioritize resources to improve plant performance.

The purpose of the Training Improvement Plan was to track through completion:

- All weaknesses and opportunities for improvement identified during the November Senior Training Advisory Committee meeting and documented in CR 04-06154.
- All corrective actions developed by the Root Cause Team and documented in CR 04-06111.
- Corrective actions identified by the Transformational Team and documented in CR 05-01164.

The objective of the Training Improvement Plan was to:

- Establish a management and site culture that drives strengthening partnerships between the line and training organizations.
- Improve the licensee's use of training to improve individual and plant performance.

The licensee identified that opportunities to improve worker performance were missed because line and training organizations did not consistently collaborate on performance issues. The licensee identified that the industry experienced an improved line-training partnership over recent years that the licensee's programs did not. The licensee identified that in some cases, the trainers were not proactive or sufficiently intrusive to advocate appropriate training involvement, and conversely, in other cases, the line organization did not involve training when appropriate. The licensee identified that senior plant management did not lead the culture change necessary to strengthen the partnership and better focus activities toward correcting performance problems.

b. Observations and Findings

Key Action 6.3: Develop Training Improvement Plan

The team reviewed the Training Development Plan and noted that the Action Plan items addressed the objectives and corrective actions identified by the Root Cause team (CR 04-06111), Transformational Team (CR 05-01164), and list of items prepared by the Senior Advisory Training Council (CR 04-06154). The team identified that about 40 percent of the action items were discovery-related, or discovery and corrective actions. Based on a review of the scheduled due dates, review of the prepared material, and interviews with the Transformational Team, the team determined that it was reasonable to expect that approximately 80 percent of the Action Plan items would be implemented by the end of April 2005. At the time of this inspection, only half of the 63 Action Plan items were implemented, with another 17 percent (11 items) requiring due date extensions. The balance of the Action Plan items were scheduled to be completed by February 2006, and consisted of incorporation of feedback into the program, and implementation of effectiveness reviews such as observations, assessments, bench-marking, and development and evaluation of PIs. The team did not identify completion of any of the effectiveness reviews items, although Management Oversight and Peer Evaluations were underway in the plant by the end of the inspection.

The team concluded that although incorporated into training programs such as Human Performance Tools and Techniques, the Training Development Plan did not directly address specific issues such as procedure usage and adherence, or workers deviating from training during stressful situations. Rather, the plan was focused on improving the use of training to improve individual and plant performance by establishing a culture to strengthen the line and training organizations partnership. The team concluded that the Training Development Plan was a focused program, and if implemented as designed, it could accomplish the identified objectives; however, based on the time to develop the culture change, and delayed implementation of the program, it was too early for the team to observe and evaluate any conclusive effects on either worker or plant performance.

4.3.6 Validations of Root Cause Actions and Effectiveness Review of Root Cause Corrective Actions Plan

a. Inspection Scope

The team reviewed the implementation of the Validation of Root Cause Actions and Effectiveness Review and Root Cause Corrective Actions Initiative, Revision 2, dated December 16, 2004. In particular, the team reviewed the following key action items prescribed in the Detailed Action & Monitoring Plan, Revision 3, dated April 4, 2005:

- Key Action 2 - Conduct an independent validation review of the corrective action implementation associated with the Air Binding of the Residual Heat Removal Waterleg Pump root cause investigation (CR 03-04764) to assess effectiveness of action plan

- Key Action 4 - Validate selected Corrective Action implementation for CR 03-04912 related to EDG Division 1 failure SVI-R43-T1317 run

- Key Action 7 - Validate selected Corrective Action implementation related to the completed EDG Latent Issues Review

Key Action 2: Corrective Action Effectiveness - Air Binding of the Residual Heat Removal Waterleg Pump

The purpose of this key action item was a validation review for the air-bound LPCS/RHR 'A' waterleg pump (CR 03-04764). The licensee planned to review all preventative and remedial corrective actions for effectiveness, as well as a review of the appropriateness of the corrective actions for the identified root causes.

During this inspection, the team independently reviewed the licensee’s corrective actions, including implementation, to address this issue and compared those results to the licensee’s results.

Key Action 4: Corrective Action Effectiveness - EDG Division 1 Failure SVI-R43-T1317

The purpose of this key action item was a validation review for the failure of the Division 1 EDG surveillance run (CR 03-04912). The licensee planned to review all preventative and remedial corrective actions for effectiveness, as well as a review of the appropriateness of the corrective actions for the identified root causes.

During this inspection, the team independently reviewed the licensee's corrective actions, including implementation, to address this issue and compared those results to the licensee's results.

Key Action 7: Corrective Action Effectiveness - EDG Latent Issues Review

The purpose of this key action item was a validation review of the effectiveness of corrective actions from the Division 1 and 2 EDG and Auxiliary Systems Latent Issues Review (Self Assessment 706DES2004). The review included corrective action implementation rigor, timeliness, and overall effectiveness.

During this inspection, the team reviewed the effectiveness of the corrective actions identified to address this area and compared the results to the licensee's results.

b. Observations and Findings

Key Action 2: Corrective Action Effectiveness - Air Binding of the Residual Heat Removal Waterleg Pump

As part of the PII, the licensee performed a validation of the root cause for air-binding of the LPCS/RHR 'A' waterleg pump (CR 03-04764). Licensee personnel determined that the evaluation had not been performed to a level of rigor required to ensure no other voids existed in ECCS piping. In order to close this gap, the licensee performed a more exhaustive review of ECCS piping and identified additional sections that had not been vented. For those areas, the licensee evaluated the effect that accumulated gas would have on system operation. In some instances, the licensee determined if gas was present through either a one time or periodic ultrasonic testing of the susceptible piping. The licensee also initiated a corrective action to install vents in some sections of piping. The team previously noted that the licensee had failed to adequately determine the extent of condition for gas voids. The PII effort provided significantly more rigor in evaluating the extent of condition and established a significantly higher level of confidence that recurrence would be prevented than the review accomplished as part of CR 03-04764.

The team identified a potential vulnerability regarding the root cause evaluation for the August 14, 2003, LPCS/RHR 'A' waterleg pump air-binding event, in that engineers used piping isometrics to evaluate and assess potential air accumulation locations, without performing actual piping field walkdowns. The team determined that this method may not be fully effective to ensure that no excessive piping slopes (reverse slopes) exist where air accumulation may occur and remain undetected.

Key Action 4: Corrective Action Effectiveness - EDG Division 1 Failure SVI-R43-T1317

The team reviewed Self Assessment 754-PII-2005, "PII Validation Review for CR 03-04912, EDG inoperability during Mode Change," to assess whether the review adequately validated the root cause actions and performed an effectiveness review of the corrective actions. The PII review identified two key corrective actions that had not been adequately implemented, and issued four CRs with follow-up actions. The PII review did not appear to independently verify the effectiveness of the listed corrective actions, since the report stated "CA 03-04912-15 is the CA [corrective action] tracking the effectiveness review..." The team did not identify any significant concerns, however, the team identified several minor issues that were not previously recognized by the licensee. Weaknesses included:

- The team identified that the PII review had failed to identify an ineffective root cause corrective action. Specifically, the corrective action to prevent recurrence for the root cause of "less than adequate rigor in post scram review reports," was not adequate to improve the quality of the PSRR. The team identified that there had been two missed opportunities to verify whether PSRR quality had improved (e.g., plant scrams in December 2004 and January 2005). The team further identified that the corrective action had revised a procedure, intended to be used for post-event crew debriefs, and that the procedure was not required to be used and, in fact, had not been used for the December 2004 and January 2005 post scram review reports. The licensee entered this issue into their CAP as CR 05-04087.

- During the CR 03-04912 root cause investigation, licensee personnel identified that during the LOOP event, when offsite power was initially restored to the 4 kV bus, there was a short period when a 4 kV bus over-voltage condition existed. The bus over-voltage condition had not been previously identified during the post scram review. The team identified that engineering informally reviewed the bus over-voltage condition to assess the impact on individual bus loads. The informal review was briefly summarized in the Root Cause Report, but was not documented in CR 03-4912 or the Root Cause Report, and was not retained as a QA plant record. In addition, engineering provided informal guidance to operations, in an e-mail, which stated that a short duration of bus voltage greater than 4400 VAC was not an operability concern (i.e., an acceptable condition). The team identified that the guidance was inconsistent with electrical DBDs, because the design limit of the 4 kV power distribution system was 4400 VAC, and engineering stated that any excursion above that design limit would require a specific engineering evaluation to assess the effects on the connected loads.

- The root cause report associated with CR 03-04912 identified a contributing cause as less than adequate procedural guidance for the use of a "Step N/A." The team determined that the implemented corrective action had not effectively corrected inappropriate usage of marking steps N/A.

Overall, the team concluded that this self assessment added value and performed a critical review of corrective action implementation, but was not fully successful in assessing the effectiveness or reasonableness of the corrective actions. As such, the

PII review may not have been sufficient to ensure that all the deficiencies which led to the original problem were corrected.

Key Action 7: Corrective Action Effectiveness - EDG Latent Issues Review

The team reviewed corrective actions to CRs initiated in the EDG Latent Issues Review. During this inspection and as detailed in Attachment 1 of this report, one issue was identified relating to an action to correct a design deficiency associated with the EDG start circuitry and the K-1 field contactor.

ATTACHMENT 3

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

L. Myers, Chief Operating Officer, First Energy Nuclear Operating Company (FENOC)
R. Anderson, Vice-President, Perry
F. von Ahn, Director, Site Operations, Perry
F. Cayia, Director, Performance Improvement, Perry
V. Hagaki, FENOC Emergency Planning Supervisor
T. Henderson, Perry Emergency Planning Unit Supervisor
K. Howard, Manager, Design, Perry
J. Lausberg, Manager, Regulatory Compliance, Perry
T. Lentz, Director, Site Engineering, Perry
J. Messina, Manager, Operations, Perry
E. Root, Manager, Perry PII (PII), Perry
M. Wayland, Manager, Maintenance, Perry

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000440/2005003-01	URI	Use of Adjustment Factor to Meet ERO Staffing Timeliness Goals (Section 3.7.3)
05000440/2005003-02	URI	Staffing ERO Positions From a Pool of Individuals (Section 3.7.3)
05000440/2005003-03	URI	Emergency Preparedness Training Methodology (Section 3.7.5)

Opened and Closed

05000440/2005003-04	NCV	Failure to Adequately Address SLC Relief Valve Test Failures (Attachment 1, Item 1.1)
05000440/2005003-05	NCV	Permanent Structures in Contact With Containment Wall (Attachment 1, Item 1.2)
05000440/2005003-06	FIN	Drywell Supply Fan Trips Due to Inadequate Maintenance (Attachment 1, Item 1.3)
05000440/2005003-07	NCV	Failure to Adequately Address LPCS/RHR 'A' Air-Binding (Attachment 1, Item 1.4)

05000440/2005003-08	NCV	Failure to Adequately Address MOV Stem Lubrication Concerns (Attachment 1, Item 1.5)
05000440/2005003-09	NCV	Failure to Comply With ARC Process During EDG Modifications (Attachment 1, Item 1.6)
05000440/2005003-10	NCV	Failure to Adequately Address Control Rod Movement Concerns (Attachment 1, Item 1.7)
05000440/2005003-11	FIN	Failure to Adequately Address Elevated Dose Rate Concerns (Attachment 1, Item 1.8)
05000440/2005003-12	NCV	Failure to Adequately Address Division 2 EDG Oil Leak Concern (Attachment 1, Item 1.9)
05000440/2005003-13	NCV	Failure to Adequately Address Scaffolding Erection Concerns (Attachment 1, Item 1.10)
05000440/2005003-14	NCV	Failure to Adequately Address EDG Design Concern (Attachment 1, Item 1.11)
05000440/2005003-15	NCV	Failure to Adequately Address ECCW Oiler Concerns (Attachment 1, Item 12)
05000440/2005003-16	NCV	Failure to Adequately Address Training Deviation Concerns (Attachment 1, Item 13)
05000440/2005003-17	NCV	Failure to Adequately Address ESW Coupling Assembly Concerns (Attachment 1, Item 14)
05000440/2005003-18	NCV	Failure to Adequately Address RWCU PCIV Closure Concerns (Attachment 1, Item 2.1)
05000440/2005003-19	NCV	Failure to Adequately Address Breaker Testing Concerns (Attachment 1, Item 2.2)
05000440/2005003-20	NCV	Failure to Comply With ARC Procedure During EDG Modifications (Attachment 1, Item 3.1)
05000440/2005003-21	NCV	Improperly Performed Verification of Electrical Disconnect Status (Attachment 1, Item 3.2)
05000440/2005003-22	NCV	Improperly Performed Verification of Electrical Jumper Removal (Attachment 1, Item 3.3)
05000440/2005003-23	NCV	Inadequate Testing Following “Hot Short” Modifications (Attachment 1, Item 4.1)

05000440/2005003-24	NCV	Inadequate Safe Shutdown MOV Design Change Assessment (Attachment 1, Item 4.2)
05000440/2005003-25	NCV	Failure to Adequately Consider Environmental Impact on TRD Modification (Attachment 1, Item 4.3)
05000440/2005003-26	NCV	Inappropriate Use of HP Technician as Interim OSCC (Attachment 1, Item 5.1)
05000440/2005003-27	NCV	Failure to Identify Impact of Security Plan Change on Emergency Plan (Attachment 1, Item 5.2)
05000440/2005003-28	NCV	Failure to Identify a Maintenance Preventable Functional Failure (Attachment 1, Item 6.1)

Closed

05000440/2005002-11	URI	Effect of EDG Operation with Open TRDs on Enclosed Tornado/Missile Enclosure (3.2b)

Discussed

05000440/2004006-01	VIO	Inadequate LPCS/RHR 'A' Fill and Vent Procedures Results in System Inoperability After Loss of Offsite Power
05000440/2004016-01	VIO	Failure to Perform Emergency Dose Assessment During and Alert Within 15 Minutes
05000440/2004005-01	VIO	Improper Maintenance Causes Emergency Service Water Pump Failure

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 team 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.

Licensee Program for Identifying, Assessing, and Correcting Performance Deficiencies

Licensee Event Reports

LER 2004-001-00, "Emergency Service Water Pump Failure," dated 7/21/04
LER 2004-001-01, "Emergency Service Water Pump Failure," dated 9/18/04
LER 2003-001-00, "Manual Actuation of the Reactor Protection System with All Control Rods Inserted During Testing," dated 7/3/03
LER 2003-002-00, "Reactor Scram as a Result of a Loss of Off-Site Power," dated 10/14/03
LER 2003-002-01, "Reactor Scram as a Result of a Loss of Off-Site Power," dated 12/12/03
LER 2003-003-00, "Unrecognized Diesel Generator Inoperability During Mode Changes," dated 10/20/03
LER 2003-003-01, "Unrecognized Diesel Generator Inoperability During Mode Changes," dated 8/3/04
LER 2003-004-00, "Emergency Service Water Pump Upper Shaft Coupling Sleeve Failure," dated 11/4/03
LER 2003-004-01, "Emergency Service Water Pump Upper Shaft Coupling Sleeve Failure," dated 1/29/04
LER 2003-004-02, "Emergency Service Water Pump Upper Shaft Coupling Sleeve Failure," dated 8/3/04
LER 2003-005-00, "TS Violation/Loss of Safety Function Due to Air Bound Water-Leg Pump," dated 12/29/03
LER 2003-005-01, "TS Violation/Loss of Safety Function Due to Air Bound Water-Leg Pump," dated 8/3/04
LER 2003-006-00, "Loss of Safety Function and TS 3.0.3 Entry Due to Support System Inoperability," dated 2/19/04

ENS Reports

ENF 39555, "Copper Sample was Above the 'Preliminary Effluent Limit (PEL)' of the NPDES Permit," dated 2/3/03
ENF 39837, "Instrument Air to Control Rods was Lost," dated 5/10/03
ENF 40126, "Division 2 Balance of Plant Isolation," dated 9/2/03
ENF 40326, "Sluice Gates Open Without ESW being Aligned Properly (retracted)," dated 11/17/03
ENF 40326, "Update to Event Notification (ENF 40326) – Retraction," dated 12/2/03
ENF 40404, "Temperature Control Valve for Division 1 ECC had 2 Blown Fuses," dated 12/22/03
ENF 40469, "Division 2 BOP Inboard Isolation Valve," dated 1/23/04

ENF 40598, “Loss of Power from the RPS ‘A’ Motor-Generator Caused the loss of Electrical Power to the RPS Instrumentation,” dated 3/19/04
ENF 40767, “ESW ‘A’ Pump Failure Results in Inoperability of All Division 1 ECCS Systems,” dated 5/21/04
ENF 40774, “ESW ‘A’ Pump Failure Resulted in Inoperability of All Division 1 ECCS Systems and Plant Shutdown,” dated 5/24/04
ENF 40821, “Maximum Licensed Power Level was Exceeded by 2 Megawatts,” dated 6/16/04
ENF 40821, ”Update to Event Notification (ENF 40821) – Retraction,” dated 8/16/04
ENF 40949, “Licensed Operator Fails Fitness For Duty Test,” dated 8/13/04
ENF 41084, “Failure of Dampers in the Emergency Recirculation Trains,” dated 10/2/04
ENF 41085, “In TS 3.0.3, Power Reduction Required,” dated 10/2/04
ENF 41084/41085, “Update to Event Notification (ENF 41084 and ENF 41085),” dated 10/2/04
ENF 41084/41085, “Retraction of ENF 41084 and ENF 41085,” dated 10/2/04

Corrective Action Review Board Meeting Minutes

CARB Meeting 03-001 Minutes dated 1/16/03
CARB Meeting 03-002 Minutes dated 1/30/03
CARB Meeting 03-003 Minutes dated 2/14/03
CARB Meeting 03-004 Minutes dated 3/3/03
CARB Meeting 03-005 Minutes dated 3/26/03
CARB Meeting 03-006 Minutes dated 4/13/03
CARB Meeting 03-007 Minutes dated 5/19/03
CARB Meeting 03-008 Minutes dated 6/30/03
CARB Meeting 03-009 Minutes dated 7/2/03
CARB Meeting 03-0010 Minutes dated 7/24/03
CARB Meeting 03-0011 Minutes dated 7/25/03
CARB Meeting 03-0012 Minutes dated 8/25/03
CARB Meeting 03-0013 Minutes dated 9/3/03
CARB Meeting 03-0014 Minutes dated 9/23/03
CARB Meeting 03-0015 Minutes dated 9/26/03
CARB Meeting 03-0016 Minutes dated 10/7/03
CARB Meeting 03-0017 Minutes dated 10/9/03
CARB Meeting 03-0018 Minutes dated 10/28/03
CARB Meeting 03-0019 Minutes dated 10/30/03
CARB Meeting 03-0020 Minutes dated 11/10/03
CARB Meeting 03-0021 Minutes dated 11/20/03
CARB Meeting 03-0022 Minutes dated 12/2/03
CARB Meeting 03-0023 Minutes dated 12/10/03
CARB Meeting 04-0001 Minutes dated 1/22/04
CARB Meeting 04-0002 Minutes dated 2/23/04
CARB Meeting 04-0003 Minutes dated 3/2/04
CARB Meeting 04-0004 Minutes dated 3/24/04
CARB Meeting 04-0005 Minutes dated 3/29/04
CARB Meeting 04-0006 Minutes dated 4/7/04
CARB Meeting 04-0007 Minutes dated 4/16/04
CARB Meeting 04-0008 Minutes dated 4/26/04
CARB Meeting 04-0010 Minutes dated 5/6/04
CARB Meeting 04-0011 Minutes dated 5/20/04

CARB Meeting 04-0012 Minutes dated 6/24/04
CARB Meeting 04-0013 Minutes dated 7/2/04
CARB Meeting 04-0014 Minutes dated 7/22/04
CARB Meeting 04-0015 Minutes dated 7/27/04
CARB Meeting 04-0016 Minutes dated 8/23/04
CARB Meeting 04-0018 Minutes dated 8/30/04
CARB Meeting 04-0019 Minutes dated 9/7/04
CARB Meeting 04-0020 Minutes dated 9/15/04
CARB Meeting 04-0021 Minutes dated 9/17/04
CARB Meeting 04-0022 Minutes dated 9/23/04
CARB Meeting 04-0023 Minutes dated 10/1/04
CARB Meeting 04-0024 Minutes dated 10/8/04
CARB Meeting 04-0025 Minutes dated 10/18/04
CARB Meeting 04-0026 Minutes dated 10/25/04
CARB Meeting 04-0027 Minutes dated 10/28/04
CARB Meeting 04-0028 Minutes dated 11/12/04
CARB Meeting 04-0029 Minutes dated 11/17/04
CARB Meeting 04-0030 Minutes dated 11/19/04
CARB Meeting 04-0031 Minutes dated 12/9/04
CARB Meeting 04-0032 Minutes dated 12/28/04

Assessment Reports

Self Assessment 283DES2002 dated 1/6/03
Self Assessment 544SPS2003 dated 11/10/03
Self Assessment 551POS2003 dated 7/30/03
Self Assessment 552POS2003 dated 7/30/03
Self Assessment 553POS2003 dated 11/1/03
Self Assessment 572SPS2003 dated 7/31/03
Self Assessment 576DES2003 dated 7/30/03
Self Assessment 579PIU2003 dated 8/6/03
Self Assessment 583FET2003 dated 5/30/03
Self Assessment 585RECS2003 dated 7/31/03
Self Assessment 586RECS2003 dated 11/11/03
Self Assessment 587PRS2003 dated 7/30/03
Self Assessment 590FAC2003 dated 7/14/03
Self Assessment 609PTS2003 dated 8/12/03
Self Assessment 622PIU2003 dated 5/30/03
Self Assessment 627OMS2003 dated 7/29/03
Self Assessment 630WCS2003 dated 7/30/03
Self Assessment 631PES2003 dated 7/30/03
Self Assessment 633RAS2003 dated 8/1/03
Self Assessment 634PMS2003 dated 7/31/03
Self Assessment 635NFD2003 dated 8/21/03
Self Assessment 636RPS2003 dated 7/30/03
Self Assessment 637PIU2004 dated 5/7/04
Self Assessment 646DES2003 dated 2/20/04
Self Assessment 648PIU2003 dated 11/5/03
Self Assessment 655RECS2004 dated 7/28/04

Self Assessment 661SPS2004 dated 3/30/04
Self Assessment 669PIU2004 dated 2/13/04
Self Assessment 670POS2004 dated 2/19/04
Self Assessment 675NFD2004 dated 9/30/04
Self Assessment 676POS2004 dated 4/26/04
Self Assessment 679OMS2004 dated 7/14/04
Self Assessment 680PMS2004 dated 8/14/04
Self Assessment 681DES2004 dated 8/10/04
Self Assessment 682PRS2004 dated 7/13/04
Self Assessment 683PES2004 dated 7/16/04
Self Assessment 685RAS2004 dated 7/15/04
Self Assessment 686PSS2004 dated 7/16/04
Self Assessment 688RPS004 dated 7/22/04
Self Assessment 689PIU2004 dated 7/15/04
Self Assessment 690POS2004 dated 4/15/04
Self Assessment 692POS2004 dated 4/26/04
Self Assessment 693POS2004 dated 10/15/04
Self Assessment 694PES2004 dated 4/29/04
Self Assessment 695PYPE2004 dated 12/21/04
Self Assessment 696DES2004 dated 4/15/04
Self Assessment 698RPS2004 dated 5/18/04
Self Assessment 706DES2004 dated 10/3/04
Self Assessment 714BETA2004 dated 7/2/04
Self Assessment 715POS2004 dated 7/13/04
Self Assessment 716POS2004 dated 7/4/04
Self Assessment 723PYPT2004 dated 11/8/04
Self Assessment 752PIU2004 dated 12/27/04
FENOC-SA-04-01 dated 9/1/04
DBAR 2003-2nd Quarter
DBAR 2003-3rd Quarter
DBAR 2003-4th Quarter
DBAR 2004-1st Quarter
DBAR 2004-2nd Quarter
QA Report PY-C-03-01 dated 4/18/03
QA Report PY-C-03-02 dated 9/3/03
QA Report PY-C-03-03 dated 11/26/03
QA Report PY-C-03-04 dated 3/5/04
QA Report PY-C-04-01 dated 4/30/04
QA Report PY-C-04-02 dated 8/20/04
QA Report PY-C-04-03 dated 11/5/04
Site Trend Report – 1/1/03 – 6/30/03 dated 9/12/03
Site Trend Report – 7/1/03 – 9/30/03 dated 10/27/03
Site Trend Report – 10/1/03 – 12/31/03 dated 2/12/04
PES System Health Report E12 2004-3rd Quarter
PES System Health Report E12 2004-2nd Quarter
PES System Health Report E12 2004-1st Quarter
PES System Health Report E12 2003-4th Quarter
PES System Health Report E12 2003-3rd Quarter
PES System Health Report E12 2003-2nd Quarter

PES System Health Report E12 2002-4th Quarter
PES System Health Report E12 2002-3rd Quarter
PES System Health Report E12 2002-2nd Quarter
PES System Health Report E12 2002-1st Quarter

Procedures

ARI-H13-P601-0018, "Leak Detection," Revision 8, dated 8/17/04
CMI-0007, "Maintenance of Limitorque Motorized Valve Operator Type SMB-000," Revision 6, dated 4/10/03
PAP-1125, "Monitoring the Effectiveness of Maintenance Program Plan," Revision 7, dated 12/17/04
Motor Operated Valve (MOV) Program Plan, Revision 4, dated 4/11/00
Motor Operated Valve (MOV) Program Plan, Revision 5, dated 4/5/04
NOP-ER-3001, "Problem Solving and Decision Making Process," Revision 0, dated 1/29/03
NOP-LP-1001, "Unescorted Access Requirements," Revision 4, dated 10/26/04
NOP-LP-2001, "Condition Report Process," Revision 9, dated 1/18/05
NOP-LP-2004, "Internal Assessment Process," Revision 2, dated 5/17/04
NOP-LP-2006, "Company Nuclear Review Board (CNRB)," Revision 0, dated 4/4/03
NOP-LP-2100, "Operating Experience Program," Revision 0, dated 1/14/05
NOP-OP-1001, "Clearance/Tagging Program," Revision 4, dated 12/18/03
NOP-TR-1001, "FENOC Conduct of Training," Revision 1, dated 1/22/04
NOP-TR-1001, "FENOC Conduct of Training, Revision 2, dated 1/26/05
NOP-TR-1002, "FENOC Training Plan Management," Revision 1, dated 10/22/04
NOP-TR-1003, "FENOC Course Management," Revision 1, dated 10/22/04
NOP-TR-1006, "FENOC Condition Report Process Qualification and Certification," Revision 0, dated 5/7/04
PAP-1125, "Monitoring the Effectiveness of Maintenance Program Plan," Revision 7, dated 12/17/04
PMI-0030, "Maintenance of Limitorque Valve Operators," Revision 8, dated 12/1/04
SVI-B21-T0253, "RHR Isolation System Functional Test," Revision 1, dated 4/10/96
SVI-B21-T1317-A, "Containment Spray A Logic System Functional Test," Revision 3, dated 9/9/93
SVI-B21-T1317-B, "Containment Spray B Logic System Functional Test," Revision 3, dated 9/24/93
SVI-B21-T1401-A, "RHR A Isolation Logic System Functional Test," Revision 4, dated 10/15/04
SVI-B21-T1401-B, "RHR B Isolation Logic System Functional Test, Revision 4, dated 11/04/04
SVI-E12-T1191, "LPCI B and C Logic System Functional Test," Revision 5, dated 2/19/03
SVI-R43-T5366, "LPCS/LPCI A Initiation and Loss of EH11 Response Time Test," Revision 9, dated 5/11/03
SVI-R43-T5367, "LPCI B and C Initiation and Loss of EH12 Response Time Test," Revision 10, dated 12/1/04
NOBP-ER-3901, "Component Classification Module 1 ER Workbench, Revision 0, dated 4/12/04
NOBP-LP-2007, "Condition Report Process Effectiveness Review, Revision 2, dated 7/12/04
NOBP-LP-2010, "CREST Trending Codes," Revision 1, dated 7/12/04
NOBP-LP-2011, "FENOC Root Cause Analysis Reference Guide," Revision 2, dated 12/16/04
NOBP-LP-2016, "FENOC Generic Implications," Revision 1, dated 12/16/04
NOBP-LP-2018, "Integrated Performance Assessment/Trending," Revision 0

NOBP-LP-2100, “FENOC Operating Experience Reference Guide,” Revision 0, dated 1/14/05
NOBP-LP-2601, “Human Performance Program,” Revision 0, dated 9/27/04
NOBP-LP-2602, “Human Performance Success Clocks,” Revision 1, dated 1/17/05
NOBP-LP-2603, “Human Performance Tools and Verification Practices,” Revision 0, dated 9/27/04
NOBP-LP-2604, “Job Briefs,” Revision 0, dated 9/27/04
PYBP-PIU-0003, “Statistical Process Control and Trending Primer,” Revision 1, dated 11/24/03
PYBP-SITE-0019, “Post Reactor SCRAM Evaluation,” Revision 0, dated 12/19/03
CAP-JFGRCE FEN-01, “Qualification Card – Root Cause Evaluator Job Familiarization Guideline,” Revision 0, dated 12/16/04
CAP-JFGCARB_FEN-01, “Qualification Card – CARB Member Job Familiarization Guideline,” Revision 0, dated 12/16/04
CAP-JFGCCE_FEN-01, “Qualification Card – Common Cause Evaluator Job Familiarization Guideline,” Revision 0, dated 12/16/04
CAP-JFGACE FEN-01, “Qualification Card – Apparent Cause Evaluator Job Familiarization Guideline,” Revision 0, dated 12/16/04
CAP-JFGCRPM_FEN-01, “Qualification Card – Condition Report Program Manager Job Familiarization Guideline,” Revision 0, dated 12/16/04
CAP-JFGCRA_FEN-01, “Qualification Card – Condition Report Analyst Job Familiarization Guideline,” Revision 0, dated 12/16/04
FEN-CAP-1000, “Common Lesson Plan – Apparent Cause Evaluator Training Course Overview,” Revision 0, dated 12/1/03
FEN-CAP-1001, “Common Lesson Plan – CR Data Gathering Skills, Revision 0, dated 12/1/03
FEN-CAP-1002, “Common Lesson Plan – CR Interviewing Skills,” Revision 0, dated 12/1/03
FEN-CAP-1003, “Common Lesson Plan – CR Evaluation Methodology Skills,” Revision 0, dated 12/1/03
FEN-CAP-1004, “Common Lesson Plan – Corrective Action Development Skills,” Revision 0, dated 12/1/03
FEN-CAP-1005, “Common Lesson Plan – CR Trend Coding Skills,” Revision 0, dated 12/1/03
CAP-RCT_FEN, “FENOC Root Cause Training,” dated 10/4/04
PII – Effective Management of the Corrective Actions Process, "Training for Management Sponsors and Corrective Actions Review Board (CARB)"
PII – Apparent Cause Analysis Training, "Performing Effective Apparent Cause Analyses”
PII, “Effective Management of the Corrective Action Process,” dated 2004
PII, “Apparent Cause Analysis Training,” dated 2004
CAP-RCT_FEN, “FENOC Root Cause Training”
FEN-CAP-1000, “Apparent Cause Evaluator Training Course Overview,” dated 12/1/03
FEN-CAP-1001, “CR Data Gathering Skills,” dated 12/1/03
FEN-CAP-1002, “CR Interviewing Skills,” dated 12/1/03
FEN-CAP-1003, “CR Evaluator Methodology Skills,” dated12/1/03
FEN-CAP-1004, “Corrective Action Development Skills,” dated 12/1/03
FEN-CAP-1005, “CR Trend Coding Skills,” dated 12/1/03

Work Orders

01-013876-000, Revision 0, dated 5/16/03
01-013902-000, Revision 0, dated 5/8/02
01-014516-000, Revision 0, dated 5/9/03
01-013864-000, Revision 0, dated 4/16/03

01-013865-000, Revision 0, dated 4/16/03
01-013892-000, Revision 0, dated 4/17/03
01-014622-000, Revision 0, dated 5/20/03
01-014623-000, Revision 0, dated 5/23/03
200003898, Revision 0, dated 4/8/04
Repetitive Task R86001538 – Replace Elastomers
Repetitive Task R89003756 – Replace Dump Valve
Repetitive Task R86001539 – Replace Elastomers and Relief Valve

Condition Reports

CR 94-0905, "Stem Thrust Variations in MOVs," dated 6/14/94
CR 96-2148, "Closure of the CR Processes Described by PAP-0606 is Scheduled for May 31, 1996. The Purpose of this PIF is to Document and Track the Remaining Items," dated 5/20/96
CR 00-2464, "As Found Test Data for MOV 1E51F0059 Did Not Meet FTI-F0016 Acceptance Criteria," dated 8/15/00
CR 01-0018, "MOV Test Data for 1E12F0064A Did Not Meet FTI-F0016 Criteria," dated 1/2/01
CR 01-0049, "Motor Operated Valve Program Issues Related to 1E12F064A," dated 1/5/01
CR 01-0080, "Request for Assistance to Evaluate GE SIL 632," dated 1/9/01
CR 01-0827, "Stem Nut From 1E12F0064C Found to Be Worn," dated 2/25/01
CR 01-0923, "As Found MOV Diagnostic Test Data for 1E51F0063 Were Unsatisfactory," dated 2/27/01
CR 01-1260, "MOV Test Data for 1G33F0004 Does Not Meet FTI-F0016 Criteria," dated 3/10/01
CR 01-1621, "Unseating Trace Anomaly on RHR Minimum Flow Valve 1E12f0064C," dated 3/24/01
CR 01-1700, "Collective Significance for Motor Operated Valve Stem Lubrication Issues," dated 3/29/01
CR 01-1766, "Unseating Thrust for HPCS Minimum Flow Valve," dated 4/5/01
CR 01-2051, "Strain Module on MOV Test Equipment," dated 5/2/01
CR 01-2902, "Motor Operated Valve Stem Lubrication Issues from NRC Inspection," dated 7/26/02
CR 01-3442, "RFA for FME Barrier Around the Reactor Building Refuel Floor Pools," dated 9/27/01
CR 01-3648, "As Found MOV Test Results for 1E12F0048B Did Not Meet FTI-F0016 Criteria," dated 10/15/01
CR 01-4236, "Document Recommendations from MOV Program Self Assessment 320 PES 2001," dated 12/12/01
CR 02-00372, "As Found Data for RCIC Test Return Valve Did Not Meet MOV Test Criteria," dated 2/5/02
CR 02-00874, "Lubrication of RCIC Trip and Throttle Valve," dated 3/25/02
CR 02-00977, "Margin Decrease of MOV 1G61F0080," dated 4/1/02
CR 02-01576, "1E12-F0048A Stem Nut Wear," dated 5/22/02
CR 02-01663, "Worn Stem Nut on RHR Motor Operated Valve," dated 5/29/02
CR 02-01721, "Low Margin of RHR 'A' Motor Operated Valve, dated 6/3/02
CR 02-03784, "Reduce FME Related Fuel Issues," dated 10/10/02
CR 02-03818, "Seating Torque Trend of ECC/NCC Butterfly Valve," dated 10/14/02
CR 02-04040, "Lube Manual Incorrectly Updated," dated 10/29/02

CR 02-04658, “As Found Data for 1E12F0003B Did Not Meet FTI-F0016 Criteria,” dated 12/10/02
CR 02-04732, “Improper Closure of CR 00-0955 (Piping Orifice Plate Issues),” dated 12/12/02
CR 03-00169, “G33 - Reactor Water Cleanup System (RWCU) Collective Significance Evaluation,” dated 1/14/03
CR 03-00409, “Stem Lube Swap from Never-Seez to Mobilgrease 28,” dated 1/28/03
CR 03-00414, “OE Review of Regulatory Issue Summary 03-01, ISI of Dissimilar Metal Welds,” dated ½8/03
CR 03-00877, “MCPR Evaluation in Relationship to Potential Channel Bowing,” dated 2/23/03
CR 03-01152, “Design Modification Product Quality/Completeness,” dated 3/10/03
CR 03-01938, “Work Performed Without Signing on as Clearance Holder or Work Order Holder,” dated 4/11/03
CR 03-03047, “MOV Stem Lubrication Issues,” dated 5/8/03
CR 03-02073, “Unintended Exposure for RWCU Heat Exchanger Work,“ dated 4/14/03
CR 03-02086, “Stop Work Order Issued to Address Radiological Control Deficiencies During RFO9,” dated 4/15/03
CR 03-02098, “Ineffective Clearance for HFA Relay Work,” dated 4/15/03
CR 03-02381, “RFA CR - Maximum Seating Torque for 1E12-F0023,” dated 4/23/03
CR 03-02383, “Contractor Work Group Failed to Address QC Concerns,” dated 4/23/03
CR 03-02409, “Receipt of FHB Gas and Iodine Alarms During Fuel Bundle Inspection,” dated 4/24/03
CR 03-02560, “As Found Thrust Decrease for RHR B Injection MOV,” dated 4/28/03
CR 03-02561, “As Found MOV Test Data for 1E12F0008 Did Not Meet FTI-F0016 Acceptance Criteria,” dated 4/28/03
CR 03-02598, “RFA - Replacing Conduit for 1E12F0410,” dated 4/29/03
CR 03-02800, “Request for Assistance to Engineering to Evaluate as Left Measured Stem Factor,” dated 5/1/03
CR 03-02814, “MOV Stem Nut Found Worn,“ dated 5/2/03
CR 03-02857, CRDM 22-35 Fasteners Not as Required,” dated 5/3/03
CR 03-03010, “Valve Stem Thread Cut Exceeded FTI-F0025 Criteria,” dated 5/7/03
CR 03-03023, “Collective Significance of LPRM Problems in RFO9,” dated 5/7/03
CR 03-03047, “MOV Stem Lubrication Issues,” dated 5/2/03
CR 03-03130, “Instrument Air Containment Isolation Valve Failed to Re-open During LOOP/LOCA,” dated 5/10/03
CR 03-03195, “RHR B Suction Pressure Low Nuisance Alarm During Pump Run,” dated 5/12/03
CR 03-03438, “Thermal Insulation and Penetration Barriers Material Condition,” dated 5/21/03
CR 03-03762, “RFA to Clarify the Licensing Basis for Operation of the RHR System,” dated 6/6/03
CR 03-03880, “Investigate Chemistry Causes for Elevated Dose Rates in RFO9,” dated 6/13/03
CR 03-04280, “Incorrect SOI Section Performed for LPCS Startup,” dated 7/17/03
CR 03-04499, “Low Margin of RHR Motor Operated Valve,” dated 7/31/03
CR 03-04529, “Plant Transient Experienced. Investigation of Cause Required,” dated 8/1/03
CR 03-04764, “RHR-A/LPCS Water-leg Pump, Not Supplying Adequate Pressure,” dated 8/15/03
CR 03-04772, “Loss of Off-site Power and Generator Trip Due to an Underfrequency Condition,” dated 8/16/03
CR 03-04901, “Unexpected Control Rod Movement,” dated 8/21/03
CR 03-04912, “Division 1 Diesel Generator Failed SVI-R43-T1317 Run,” dated 8/21/03

CR 03-04927, “Spurius ‘RHR A Out of Service" Alarm,” dated 8/22/03
CR 03-05065, “ESW Pump A Failed,” dated 9/1/03
CR 03-05281, “RFA for Circuit Breaker Modifications,” dated 9/16/03
CR 03-05307, “Past Operability Concern for LPCS/RHR A Waterleg Pump 1E21C0002,” dated 9/16/03
CR 03-05502, “RFA for Self-assessment 621PNPPD2003 Recommendations for AFI Eq.1-3 (CR 02-02066),” dated 9/29/03
CR 03-05528, “Assessment PY-C-03-03; MOV Program Deficiencies,” dated 9/30/03
CR 03-05555, “PY-C-03-03 RFA - MOV Program Enhancements, Recommendations,” dated 10/2/03
CR 03-05631, “RHR A Vibration in Alert Range,” dated 10/7/03
CR 03-05745, “Lifted 2 SRVs During the Performance of SVI-B21-T0369B,” dated 10/15/03
CR 03-05927, “NOP-ER-3001 Not Consistently Used; Disconnect with NOP-IP-2001 and NOBP-IP-2009,” dated 10/28/03
CR 03-05995, “Collective Significance Review - Safety System Failures,” dated 10/31/03
CR 03-06213, “Incorrect SOI Section Used to Lineup ESW for Swale Operation,” dated 11/17/03
CR 03-06398, “Trip of RPS B System,” dated 11/29/03
CR 03-06688, “Audit PY-C-03-04, Declining Trend in Inattention to Detail Events,” dated 12/18/03
CR 03-06739, “1P42-F665A Disconnect EF1A09-S Blown Fuses,” dated 12/21/03
CR 03-06778, “Safety Culture Assessment Attribute 5 Rated Yellow,” dated 12/23/03
CR 03-06841, “RFA - CR NOP Requires SR - Root Cause Evaluations for CFR 50.72 and 50.73 Reports,” dated 12/30/03
CR 04-00249, “Loss of LH2A Not Recognized in PWIS,” dated 1/21/04
CR 04-00371, “Thermography Indicates Abnormal Heating on Fuse C71-F18D,” dated 1/27/04
CR 04-00901, “Loss of RPS ‘A’ Normal During Weekly Manual Scram SVI, Causes Entry Into ONI-C71-2,” dated 2/22/04
CR 04-00920, “Review Numerous RPS Component Issues in Aggregate,” dated 2/23/04
CR 04-00935, “Repeat Finding: Failure to Meet M&TE Program Traceability Requirements,” dated 2/24/04
CR 04-01404, “Off-hours ERO Unannounced Drill,” dated 3/19/04
CR 04-01638, “Collective Review of Human Performance Errors in the Maintenance Department,” dated 4/1/04
CR 04-01683, “INPO 2004 AFI - OR.2-2 Organization Effectiveness on Standards and Accountability,” dated 4/5/04
CR 04-01688, “INPO 2004 AFI OR.3-1 - Perform Shortfalls in Individual and Organization Behavior,” dated 4/5/04
CR 04-01857, “Testing of Relay 1E22KQ039 Initiated Air Roll of Division 3 Diesel Generator,” dated 4/10/04
CR 04-01795, “MOV Stem Nut Found Worn,” dated 4/8/04
CR 04-02331, “Apparent Cause Investigation Does Not Meet NOP-IP-2001 Requirements,” dated 5/7/04
CR 04-02598, “ESW Pump A Failure,” dated 5/21/04
CR 04-02870, “PCR - Deficiency SVI-E12-T2023, SVI-E12-T1182B, SVI-E12-T1182C,” dated 6/1/04
CR 04-02900, “Concern Per NOP-LP-2003 Section 3.3,” dated 6/2/04
CR 04-02947, “3 Blown Mainline Fuses on E12-F004A,” dated 6/3/04

CR 04-03020, “Potential Training Results Issue Identified During the 95002 Inspection,” dated 6/8/04
CR 04-03145, “Feedwater Temperature Rtd 1B21N0041D,” dated 6/15/04
CR 04-03616, “Condensate Storage Tank Examination,” dated 7/13/04
CR 04-03634, “Effectiveness Review of CR 03-05065,” dated 7/14/04
CR 04-04059, “Site Human Performance Barriers May Be Lost During Stressful Times,” dated 8/5/04
CR 04-04084, “Class 1E Switchgear Bolts Not Secured Properly,” dated 8/7/04
CR 04-04405, “Engineering Focused Self-Assessment FENOC-SA-04-01, Review Engineering Programs,” dated 8/26/04
CR 04-04531, “Updates to Risk-Informed Calculations,” dated 9/1/04
CR 04-04603, “Determine If the Local Push Button on Breaker EH1110 Is Acceptable for Use,” dated 9/7/04
CR 04-04613, “EH1110 Loose Screws in Local Button,” dated 9/7/04
CR 04-04812, “1E12N0013 Needs Calibration Check,” dated 9/18/04
CR 04-04948, “Evaluate Performance of HPCS Pump During SVI-E22-T2001,” dated 9/23/04
CR 04-05077, “HPCS Unavailable Time for Work on E22-F0010 Not Recognized Prior to Performing,” dated 9/29/04
CR 04-05130, “Effectiveness Review of Corrective Actions of CR 03-02073 Ineffective,” dated 10/1/04
CR 04-05114, “Individual with Hearing Protection Not Notified to Evacuate,” dated 9/30/04
CR 04-05344, “RHR B - EH1208 Breaker Failure,” dated 10/12/04
CR 04-06111, “Skills Accreditation Team Finding ACC1-1, Training for Performance Improvement,” dated 11/19/04
CR 04-06413, “Failure to Control Trainees During the Initial License Class Simulator Exam,” dated 12/7/04
CR 04-06581, “1G33-F0034 RWCU Isolation Failed to Close,” dated 12/14/04
CR 04-06675, “Preventive Action Closed Based on Enhancement Actions Being Developed.,” dated 12/20/04
CR 04-06715, “Negative Trend in FME Controls in Containment/Pool Areas,” dated 12/21/04
CR 04-06763, “Reactor Scram Report,” dated 12/24/04
CR 04-06766, “Unexpected Transfer of Both Reactor Recirculation Pumps from Fast to Slow Speed,” dated 12/24/04
CR 04-06796, “Results of Independent Assessment of CR 04-06766 Immediate Investigation,” dated 12/26/04
CR 04-06799, “Evaluate Operator Response to Recirculation Pump Downshift,” dated 12/27/04
CR 04-06807, “RFA - PRA Impact from B33 Pump Downshift Scenarios,” dated 12/27/04
CR 05-00094, “Reactor Scram Investigation,” dated 1/6/05
CR 05-00145, “Decision Making Following December 23 Reactor Recirculation Pump Downshift,” dated 1/7/05
CR 05-00162, “PY-C-05-01: Lower Standards, Procedure Deficiencies Within NOBP-OM-4010,” dated 1/8/05
CR 05-00171, “PY-C-05-01: 12/23/04 Forced Outage Restart Readiness Meeting Minutes Not Issued,” dated 1/8/05
CR 05-00188, “PY-C-05-01 Immediate Investigation CR 04-06763 Scram Report Is Not Accurate,” dated 1/9/05
CR 05-00349, “NOP-LP-2001 Definition of Adverse Trend,” dated 1/14/05
CR 05-00352, “Human Performance Stand-down Improvements,” dated 1/14/05

CR 05-00353, CR Categories/Evaluation Assignments for Non-Equipment Related Issues," dated 1/14/05
CR 05-00354, "MOV Stem Lubrication Issues," dated 1/14/05
CR 05-00472, "PII B1.13 FME Program Review Report Rejected," dated 1/20/05
CR 05-00671, "NRC IEN 2003-3 Inadequately Staked Capscrew Renders RHR Pump Inoperable," dated 1/26/05
CR 05-00682, "Tracking CR to Evaluate Impact on MOV Program Due to Revision to Calculation 6.8," dated 1/27/05
CR 05-00692, "'Production over Safety' Concern; Safety Conscience Work Environment Concern," dated 1/27/05

Drawings

D-302-641, "RHR – P&ID," Revision WW
D-302-642, "RHR – P&ID," Revision CC
D-302-643, "RHR – P&ID," Revision SS
B-208-0055-00000, "Residual Heat Removal System Index," Revision J
B-208-0055-00001, "Residual Heat Removal System Valve and Control Tabulation," Revision V
B-208-0055-00002, "Residual Heat Removal System Switch ," Revision T
B-208-0055-00003, "Residual Heat Removal System Relay Tabulation," Revision HH
B-208-0055-00004, "Residual Heat Removal System Power Distribution for Testability," Revision PP
B-208-0055-00005, "Residual Heat Removal System Power Distribution," Revision AA
B-208-0055-00006, "Residual Heat Removal System Power Distribution," Revision R
B-208-0055-00007, "Residual Heat Removal System Relay Logic Bus A," Revision DD
B-208-0055-00008, "Residual Heat Removal System Relay Logic Bus B," Revision CC
B-208-0055-00009, "Residual Heat Removal System Relay Logic Bus B," Revision T
B-208-0055-00010, "Residual Heat Removal System Process Instrumentation," Revision CC
B-208-0055-00011, "Residual Heat Removal System Process Instrumentation," Revision BB
B-208-0055-00012, "Residual Heat Removal System MCC Power Loss," Revision U
B-208-0055-00013, "Residual Heat Removal System Computer Inputs and Status Lights," Revision T
B-208-0055-00014, "Residual Heat Removal System Testability (A)," Revision P
B-208-0055-00015, "Residual Heat Removal System Testability (B)," Revision W
B-208-0055-00016," Residual Heat Removal System Testable Check Valves F041A, F041B, & F041C," Revision S
B-208-0055-00017, "Residual Heat Removal System RHR Pump C002A," Revision V
B-208-0055-00018, "Residual Heat Removal System RHR Pump C002B," Revision Z
B-208-0055-00019, "Residual Heat Removal System RHR Pump C002C," Revision V
B-208-0055-00020, "Residual Heat Removal System Waterleg Pump C003," Revision M
B-208-0055-00021, "Residual Heat Removal System RHR Pump C002A Suction MOV F004A," Revision R
B-208-0055-00022, "Residual Heat Removal System RHR Pump C002B Suction MOV F004B," Revision V
B-208-0055-00023, "Residual Heat Removal System RHR Pump C002C Suction MOV F105," Revision P
B-208-0055-00024, "Residual Heat Removal System Containment Spray Valve F028A," Revision V

B-208-0055-00025, “Residual Heat Removal System Containment Spray Valve F028B,” Revision X
B-208-0055-00026, “Residual Heat Removal System Containment Spray Valve F537A,” Revision S
B-208-0055-00027, “Residual Heat Removal System Containment Spray Valve F537B,” Revision R
B-208-0055-00028, “Residual Heat Removal System Shutdown Cooling Valve F006A,” Revision V
B-208-0055-00029, “Residual Heat Removal System Shutdown Cooling Valve F006B,” Revision X
B-208-0055-00030, “Residual Heat Removal System RHR 'A' Injection MOV F027A,” Revision M
B-208-0055-00031, “Residual Heat Removal System RHR 'B' Injection Valve F027B,” Revision R
B-208-0055-00032, “Residual Heat Removal System RHR Injection MOV F042A,” Revision T
B-208-0055-00033, “Residual Heat Removal System RHR Injection MOV F042B,” Revision W
B-208-0055-00034, “Residual Heat Removal System RHR Injection MOV F042C,” Revision P
B-208-0055-00035, “Residual Heat Removal System RHR 'A' Test Return MOV F024A,” Revision V
B-208-0055-00036, “Residual Heat Removal System RHR 'B' Test Return MOV F024B,” Revision V
B-208-0055-00037, “Residual Heat Removal System RHR "C" Test Return MOV F021 (Throttle Valve),” Revision N
B-208-0055-00038, “Residual Heat Removal System RHR Pump Minimum Flow MOV F064A,” Revision S
B-208-0055-00039, “Residual Heat Removal System RHR Pump Minimum Flow Valve F064B,” Revision S
B-208-0055-00040, “Residual Heat Removal System RHR Pump Minimum Flow MOV F064C,” Revision P
B-208-0055-00041, “Residual Heat Removal System Steam Pressure Reducing Valve F051A Cond. Discharge to Suppression Pool or RCIC W. F065A,” Revision H
B-208-0055-00042, “Residual Heat Removal System Steam Pressure Reducing Valve F051B Cond. Discharge to Suppression Pool or RCIC W. F065B,” Revision K
B-208-0055-00043, “Residual Heat Removal System Shutdown Manual Suction Valve F010, RHR 'A', 'B', "C" Manual Injection Valve F038A,B,C,” Revision J
B-208-0055-00044, “Residual Heat Removal System Shutdown Cooling Upper Pool MOV F037A (Throttle Type),” Revision U
B-208-0055-00045, “Residual Heat Removal System Shutdown Cooling Upper Pool MOV F037B (Throttle Valve),” Revision W
B-208-0055-00046, “Residual Heat Removal System Shutdown Cooling Injection MOV – F053A (Throttle Type),” Revision T
B-208-0055-00047, “Residual Heat Removal System Shutdown Cooling Injection MOV – F053B (Throttle Valve),” Revision S
B-208-0055-00048, “Residual Heat Removal System Heat Exchanger – Shell Side Inlet MOV F047A,” Revision P
B-208-0055-00049, “Residual Heat Removal System Heat Exchanger – Shell Side Inlet MOV (F047B),” Revision R
B-208-0055-00050, “Residual Heat Removal System Heat Exchanger-Shell Side Outlet MOV F003A (Throttle Valve),” Revision T

B-208-0055-00051, Residual Heat Removal System Heat Exchanger-Shell Side Outlet MOV F003B (Throttle Valve)," Revision T
B-208-0055-00052, "Residual Heat Removal System RHR Heat Exchanger – Flow to RCIC MOV F026A," Revision P
B-208-0055-00053, "Residual Heat Removal System RHR Heat Exchanger – Flow to RCIC MOV F026B," Revision P
B-208-0055-00054, Residual Heat Removal System RHR Heat Exchanger Flow to Suppression Pool MOV F011A (Throttle Type)," Revision M
B-208-0055-00055, "Residual Heat Removal System – RHR Heat Exchange Flow to Suppression Pool MOV F011B (Throttle Type)," Revision P
B-208-0055-00056, "Residual Heat Removal System Heat Exchanger-Shell Side Bypass MOV F048A (Throttle Valve)," Revision R
B-208-0055-00057, "Residual Heat Removal System Heat Exchanger-Shell Side Bypass MOV F048B (Throttle Valve)," Revision P
B-208-0055-00058, "Residual Heat Removal System Heat Exchanger Vent MOV F073A (Throttle Valve)," Revision S
B-208-0055-00059, "Residual Heat Removal System Heat Exchanger Vent MOV F073B," Revision V
B-208-0055-00060, "Residual Heat Removal System Heat Exchanger Vent MOV F074A Throttle Valve ," Revision S
B-208-0055-00061, "Residual Heat Removal System Heat Exchanger Vent MOV F074B (Throttle Valve)," Revision S
B-208-0055-00062, "Residual Heat Removal System Steam Line Isolation MOV F087A (Throttle Valve)," Revision M
B-208-0055-00063, "Residual Heat Removal System Steam Line Isolation Valve F087B (Throttle Valve)," Revision P
B-208-0055-00064, "Residual Heat Removal System Steam Line Isolation MOV F052A (Throttle Valve)," Revision S
B-208-0055-00065, "Residual Heat Removal System Steam Line Isolation Valve F052B (Throttle Valve)," Revision U
B-208-0055-00066, "Residual Heat Removal System Suppression Pool Cooling Via RHR Bypass Valve F609," Revision B
B-208-0055-00067, "Residual Heat Removal System Suppression Pool Cooling Via RHR Bypass Valve F610," Revision B
B-208-0055-00069, "Residual Heat Removal System RHR 'A' Heat Exchanger Performance Monitoring"
B-208-0055-00070, "Residual Heat Removal System RHR 'B' Heat Exchanger Performance Monitoring"
B-208-0055-00100, "Residual Heat Removal System LOCA Signal," Revision P
B-208-0055-00101, "Residual Heat Removal System Combined LOCA Signal," Revision V
B-208-0055-00102, "Residual Heat Removal System LOCA Signal," Revision N
B-208-0055-00103, "Residual Heat Removal System Combined LOCA Signal," Revision U
B-208-0055-00105, "Residual Heat Removal System Inoperable and Bypass," Revision J
B-208-0055-00106, "Residual Heat Removal System Inoperable and Bypass," Revision J
B-208-0055-00107, "Residual Heat Removal System Flushing Water Valves," Revision E
B-208-0055-00108, "Residual Heat Removal System Testable Check Valves E12-F597A (B,C)," Revision C
D-412-066, "Miscellaneous Embedded Steel," Revision K
D-412-101, "Floor Slab – Concrete Outline East," Revision N

D-412-110, “Auxiliary Building Hatch Covers Concrete Outline,” Revision E
D-412-203, “Auxiliary Building Hatch Cover Details Concrete Outline and Reinforcing Placement,” Revision C
D-412-222, “Auxiliary Building Floor Slab El. 620’- 6" (East) Concrete Outline,” Revision U
D-304-431, “E12 Residual Heat Removal Auxiliary Bldg.,” Revision R/E
D-304-646, “E12 Residual Heat Removal Auxiliary & Reactor Bldg.,” Revision H
SS-304-643-104, “Residual Heat Removal System Auxiliary Building,” Revision G
SS-304-650-101, “Residual Heat Removal System Reactor Building,” Revision A
SS-304-640-118, “Residual Heat Removal System Auxiliary Building,” Revision B
SS-304-643-103, “Residual Heat Removal System Auxiliary Building,” Revision A
SS-304-641-107, “Residual Heat Removal System Auxiliary Building,” Revision A
SS-304-641-106, “Residual Heat Removal System Auxiliary Building,” Revision A
SS-304-641-113, “Residual Heat Removal System Auxiliary & Reactor Building,” Revision C
SS-304-643-104, “Piping Isometric Residual Heat Removal System Auxiliary Building,” Revision G
SS-304-642-112, “Residual Heat Removal System Auxiliary Building”
SS-304-641-117, “Residual Heat Removal System Auxiliary Building,” Revision A
SS-304-641-116, “Piping Isometric Residual Heat Removal System Auxiliary Building,” Revision B
SS-705-643-109, “ISI Piping ISO System Residual Heat Removal Loop ‘B’ Auxiliary Building,” Revision C

Miscellaneous Documents

Maintenance Rule Database E12 Functions
Chemistry Standing Order 04-002 dated 2/4/04
Temporary Modification Technical Evaluation G42 – Tag Order Number 1-03-0026
Installation Standard Specification 2701, dated 11/2/04
Motor Feed Pump Problem Solving Plan, Revision 0
Motor Feed Pump Failure Mode Analysis, Revision 0
Maintenance Plan 73108
Maintenance Plan 73109
Operability Determination CR 05-000354 dated 1/16/05
RFO10 Work Plan – Undervessel Work dated 2/18/04
Performance Indicators, 2001 – 2004
CAP Indicators, 2001 – 2004
Perry Nuclear Power Plant – PII Fuel Reliability Improvement Strategic Plan dated 11/15/04
FME Plan for New Fuel Receipt
Foreign Material Exclusion Control Plan for the Refuel Floor and Fuel Handling Building dated 11/11/04
Surveillance Number 10132-S012 dated 12/6/04-12/10/04
Fuel Reliability Improvement Actions Through RFO10 dated 12/7/04
Integrated Fuel Solution Team
Design Interface Summary – Calculation 6.8 dated 11/10/04
Root Cause Analysis Report – Reactor Recirculation Pump Speed Shift CR 2005-00094 dated 1/22/05
Root Cause Analysis Report – Unexpected Control Rod Movement CR 03-04901dated 10/2/03
Calculation PSA-047 dated 11/1/04
Maintenance Rule Functions, Performance Criteria and Classifications dated 7/23/04

Perry Plant Management Issue List – (Top Ten Site Issues) dated 2/3/05
Effectiveness Review Form (NOBP-LP-2007-01) Revision 0
Human Performance Program Binder
Flow Accelerated Corrosion Examination Results for the RHR Systems
Effectiveness Review Form – CA 03-05065-22 dated 8/15/04
Effectiveness Review Form – CA 03-02073-9 dated 10/1/04
OE19025, "Preliminary – Reactor Water Clean Up Backwash Tank Overflowed, With Subsequent Contamination of lower Reactor Building Levels," dated 2/9/04
PY-CEI/NRR 1849L, "Amended Response to Generic Letter 89-10 Supplement 6 Information on Schedule and Grouping and Staff Responses," dated 9/23/94
GE SIL 632, "Pressure Drop Due to LPCI Flow Deflector," dated 12/20/00
RIS 2003-01," NRC Regulatory Issue Summary 2003-01: Examination of Dissimilar Metal Welds, Supplement 10 to Appendix VIII of Section XI of the ASME Code," dated 1/21/03
IN 2003-03, "NRC Information Notice 2003-03: Part 21 – Inadequately Staked Capscrew Renders Residual Heat Removal Pump Inoperable," dated 1/27/03

Performance in the Reactor Safety Strategic Performance Area

Key Attribute - Design

Calculations

PMRV-0001, Revision 3, "Division 1 & 2 Diesel Generator Protection"
Sizing Calculation for Relief Valve 1R44F0518A/B
E12-048, Revision 1, "Determine the System Pressure Drop of the RHR/LPCI Injection Mode with Injection Valve 1E12-F0042C Open Less Than 100% as a Result of the Stroke Time for the Valve Being Increased"
E12-064, Revision 0, "Provide Input to SOI E12 Regarding Flow Required Through E12F0024A/ZB Before Securing Suppression Pool Cooling or Test Return Mode of RHR Resulting Flow Assures System High Point Piping Will Not Void Upstream"
E12-088, Revision 1, "Residual Heat Removal System Hydraulic Calculation"
M39-016, Revision 0, "ECCS Pump Room Coolers Design Airflows"
M43-000, Revision 2, "Diesel Generator Building Ventilation System"
M43-002, Revision 0, "When Diesel is in Standby Condition, Keep-Warm Systems Add Considerable Cooling Load to Normally Unventilated Diesel Rooms"
R43-054, Revision 0, "The Bolting for the Jacketwater Outlet Flange of the Left Bank Turbocharger for 1R43C0001B Does Not Have Full Thread Engagement. This Calculation Justifies Use-As-Is"
R45-003, Revision 1, "Diesel Fuel Oil Pumps"
R45-007, Revision 2, " Emergency System Diesel Generator Fuel Oil Day Tank Level/Volume"
R45-008, Revision 2, "R45 Operating Temperatures"
R45-009, Revision 5, "Standby and HPCS Diesel Generator 7 Day Event Fuel Consumption"
R45-010, Revision 4, "Correlation of Tank Level to Volume for Diesel Fuel Oil Storage Tanks - 1R45A0002A (Division 1), 1R45A002B (Division 2) and 1R45A0004 (Division 3)"
R45-011, Revision 0, "EDG Fuel Oil Transfer Pump Performance Requirements"
R45-012, Revision 2, "High Pressure Core Spray and Division 1 and 2 Diesel Fuel Oil Day Tank"
R45-014, Revision 0, "Assessment of Fuel Oil Transfer From Fuel Oil Storage Tank to Day Tank"

R46-018, Revision 2, “Design Basis Heat Load and Required ESW Flow for the Division 1 and 2 Diesel Generator Jacket Water Heat Exchangers”
R47-002, Revision 0, “Sizing of Lube Oil Supply Line to Diesel Generator Turbocharger”
R47-003, Revision 0, “Sensitivity Study on the Effects of Resizing the Turbocharger Lube Oil Supply Lines”
R48-015, Revision 0, “Pressure/Temperature Ratings for Standby and HPCS EDG Exhaust Piping
R48-018, Revision 1, “Division 1 and 2 Exhaust Vent Valve Maximum Back Pressure”
R48-023, Revision 0, “Division 1 and 2 Testable Rupture Disc (TRD) Design and Setpoints”
VQ-020, Revision 0, “Standby and High Pressure Core Spray Diesel Generator Exhaust Vent Valve Seismic Qualification”
PTSG-0014, Revision 6, “Electrical Load Determination of Division 1, 2, and 3 Diesel Generators”
PTSG-0017, Revision 1, “Division 1 and 2 Diesel Generators 7 Day Kilowatt Loading for Fuel Oil Consumption”
ECA-008, Revision 3, “Determine Steady State Temperature Profiles for Environmental Zones AB-3, AB-4, AB-7, AB-8, AB-9, AB-10 Under Various Operating Conditions”
ECA-020, Revision 1, “RHR Pump Room - Transient”
ECA-050, Revision 1, “Determine Average and Maximum Plant Normal Mode Environmental Temperatures for Zones AB-1 through AB-9"
ECA-018, Revision 4, “Environmental Conditions Analysis (DG-1)”
E12-C07, Revision 1, “LPCI A/B/C Injection Pressure Permissive”
R45-C01, Revision 9, “Division 1 and 2 Fuel Oil Day Tank Level Switch Tolerance for 1R45N0140A/B, N0150A/B”
R45-C03, Revision 1, “Safety-Related Tolerance Calculation for EDG Fuel Oil Pressure Switch 1R45N0018A/B”
R45-C04, Revision 0, “Division 1 and 2 Fuel Oil Day Tank Improved TS Volume Calculation”
E12-001, Revision 0, “Residual Heat Removal System Net Positive Suction Head Calculations”
E12-078, Revision 3, “SVI-E12-T2001/T2002 RHR-A Pump Performance Acceptance Criteria”
E12-079, Revision 3, “SVI-E12-T2003 RHR-C Pump Performance Acceptance Criteria”
E12-008, Revision 1, “Determine Pressure Containing Design Adequacy of RHR Piping Subsystem Between Outboard Isolation Valves 1E12F0027A/B and Inboard Isolation Valves 1E12F0042A/B, 1E12F0037A/B, 1E12F0028A/B”
E12-097, Revision 0, “Water Hammer in RHR Piping”
PTSG-0001, Revision 4, “PNPP Auxiliary System Voltage Study”
PTSG-0006, Revision 3, “PNPP Short Circuit Study”
PTSG-0010, Revision 2, “Validation of PNPP Class 1E Auxiliary System Voltage Analysis”
R48-008, Revision 1, “EDG Exhaust Vent Valve Size”
E12-C02, Revision 0, “Containment Spray Timer Setpoints”
E12-C07, Revision 1, “LPCI A/B/C Injection Pressure Permissive”
PMRV-0020, Revision 2, “Degraded Voltage and Loss of Offsite Power Undervoltage Relaying for Division 1, 2, and 3"
TM 05-0002, “Install a Foreign Material Exclusion (FME) Barrier to Prevent Spalling Concrete From Entering the EDG Exhaust Through the Testable Rupture Disk”
TM 05-0003, “Install a Foreign Material Exclusion (FME) Barrier to Prevent Spalling Concrete From Entering the EDG Exhaust Through the Testable Rupture Disk”
TM 05-0005, “Provide an Insulated Heat Shield Enclosure Around Each EDG’s Pair of Vent Lines From the Fuel Oil Day Tank and Generator Lube Oil Tank/Crankcase Breather”
AS-011, Revision 2, "Accident Sequences - ATWS Event Trees"

C41-008, Revision 4, "Standby Liquid Control System"
C41-008, Revision 4, Addendum 1
C41-016, Revision 1, "C41-C0001 SLC Injection Pump Performance Acceptance Criteria"
EA-0241, Revision 0, "ASME Class 2&3 Relief Valve Expanded Set Press. Acceptance Criteria"
FSPC-0018, Revision 6, "Fuse Size Calculations"
PSTG-0001, Revision 4, "Class 1E Power Distribution System Voltage Study"
SQ-0093, Revision 1, "Stall Thrust Evaluation for IN 92-18"
SSC-001, Revision 3, "Appendix-R Evaluation: Safe Shutdown Capabilities Report"
SSC-001, Revision 3, Addendum 1

10 CFR 50.59 Reviews

RAD 04-01143, “Division 2 Standby Diesel Generator Fuel Oil Piping”
RAD 04-01195, “Use-As-Is Disposition for Two Stripped Holes”
RAD 04-01200, “Installation of Improved TRD on Division 2 Diesel Generator”
RAD 04-01378, Modification to Eliminate Vibration Trip Sensors from
RAD 04-01499, “Operability Test of 1R48-D014B Testable Rupture Disk”
RAD 04-01694, “Corrective Action to Revise Calculation R45-10"
RAD 04-01705, “Diesel Generator Building Ventilation System Damper”
RAD 04-01735, “Revise Calculation R45-T04"
RAD 04-01759, “EDG Fuel Oil Storage Tanks Capacity”
RAD 04-01770, “Division 1 and 2 Diesel Generator Fuel Oil”
RAD 04-01867, “Operability Test of 1R48-D014A Testable Rupture Disk”
RAD 05-00544, “Temporary Modification for Protection of Divisions 1 and 2 Emergency Diesel Generator Fuel Oil Day Tank Vent Lines and Lube Oil Tank/Crankcase Breather Vent Lines”
RAD 05-01082, “Division 1, 2, and 3 Emergency Diesel Generator Testable Rupture Disks”
RAD 03-00278, “Replace Valve 1E12-F0608"
RAD 03-01301, “Temporary Modification for Alternate Cooling of Suppression Pool”
EVAL 04-01200, “Installation of Improved TRD on Division 2 Diesel Generators - Revision 2"
EVAL 04-01378, “Modification to Eliminate Vibration Trip Sensors From Division 1 and 2 EDGs”

Design Change Packages

DCP 99-5011A, "RHR E12-F011A Hot Short Modification"
DCP 00-5030, "Raise Level Transmitter above Potential Water Level in EDG FOST"
ECP 04-0092, "Division 1 EDG Vibration Switch Removal"
ECP 04-0092-01, "Division 2 EDG Vibration Switch Removal"
FSCR 96-0004, "ESW P45-F068A Fuse Size Change"
FSCR 96-0005, "ESW P45-F130A Fuse Size Change"
FSCR 96-0008, "RCIC E51-F022 Fuse Size Change"
SPC 99-1005, "Time Delay Setting Change for R43-Q7002A"
SPC 99-1108, "Level Instruments for Div-1 EDG FOST"

Drawings

206-0017-00000; Class 1E Bus EH11 & EH12; Revision EE
208-0055-00007; RHR System Relay Logic Bus A; Revision DD
208-060-A04; LPCS Relay Logic & Testable Check Valve F006; Revision Z
208-0135-00001; Diesel Generator Bldg. Ventilation Fan C001B; Revision BB

208-0135-00002; Diesel Generator Bldg. Ventilation Fan C001C; Revision CC
208-0135-00003; Diesel Generator Bldg. Ventilation Fan C001A; Revision Z
208-0216-00016; Standby Diesel Generator Control Panel Division 2 1 R43-S001B; Revision T
208-0216-00027; Standby Diesel Generator Control Switch Development, Division 2 1R43-S001B; Revision K
208-0055-54, Revision L, "Electrical Schematic RHR E12-F011A"
208-0055-54, Revision M, "Electrical Schematic RHR E12-F011A"
208-0055-55, Revision P, "Electrical Schematic RHR E12-F011B"
302-0271, Revision M, "Safety Related Instrument Air System P&ID"
302-0605, Revision W, "Nuclear Boiler System P&ID"
302-0608, Revision M, "Nuclear Boiler System P&ID"
302-0631, Revision AA, "Reactor Core Isolation Cooling (RCIC) System P&ID"
302-0632, Revision JJ, "RCIC P&ID"
302-0641, Revision WW, "Residual Heat Removal (RHR) System P&ID"
302-0642, Revision CC, "RHR P&ID"
302-0643, Revision SS, "RHR P&ID"
302-0691, Revision T, "Standby Liquid Control System P&ID"
302-0692, Revision R, "Standby Liquid Control System P&ID"
302-0791, Revision PP, "Emergency Service Water (ESW) System P&ID"
302-0792, Revision JJ, "Emergency Service Water (ESW) System P&ID"
302-0244, Revision J, "Instrument Air System P&ID"
10776-6-1, Revision 6, "EDG Fuel Oil Storage Tank"
10776-6-2, Revision 4, "EDG Fuel Oil Storage Tank"

Procedures

FTI-F0036, Revision 3, "Post Maintenance Test Manual"
GEI-0048, Revision 2, "Low Voltage Control Circuit Testing"
GMI-0008, Revision 12, Pressure Relief Device Bench Testing"
IOI-011, Revision 10, "Shutdown from Outside the Control Room"
IOI-011, Revision 11, "Shutdown from Outside the Control Room"
NOP-CC-2004-03, Revision 7, "Design Interface Checklist - PY"
NOP-LP-2601, Revision 0, "Procedure Use and Adherence"
NOP-OP-1002, Revision 1, "Conduct of Operations"
NOP-SS-3001, Revision 5, "Procedure Review and Approval"
NOP-SS-3007, Revision 1, "Nuclear Operating Procedure Writer's Guide"
NOP-WM-4300, Revision 0, "Work Order Execute Process"
OAI-0201, Revision 4, "Operations General Instructions and Operating Practices"
PAP-0528, Revision 3, "Procedure Use and Adherence"
PAP-0905, Revision 16, "Work Order Process"
PAP-0905, Revision 24, "Work Order Process"
SOI-C11 (RCIS), Revision 18, "Rod Control and Information System"
SOI-C61, Revision 2, "Remote Shutdown System"
SVI-C61-T1200, Revision 1, "Remote Shutdown Control Test - RCIC & RHR"
SVI-C61-T1201, Revision 0, "Remote Shutdown Panel Test - A-RHR, A-ESW, & A-ECC"
SVI-R45-T1323, Revision 3, "Remove Water from EDG Fuel Oil Storage tanks"
SVI-R43-T1338, Revision 13, "Routine EDG Surveillance Test"
TAI-1101-3, Revision 2, "Inservice Testing of ASME Relief Devices"

Work Orders

96-04119, "Hot Short Mod for E51-F064"
97-01167, "Hot Short Mod for E12-F074A"
97-01177, "Hot Short Mod for E51-F006A"
00-02080, "Hot Short Mod for E12-F011A"
01-15289, "Remove Division 1 EDG Vibration Switches"
01-46872, "RHR E12-F011A Hot Short Mod"
01-46872-01, "Previous Hot Short Mod Testing of MOVs"
TXI-319, "Post Modification Testing of E12-F011A for DCP 99-5011A"

Condition Reports

CR 04-04549, “Installation of Division 2 Vibration Switches”
CR 04-04579, R45 FOST [Fuel Oil Storage Tank] ASME Code Compliance”
CR 04-04637, “Spurious Alarm Division 1 Diesel”
CR 04-04750, “Division 2 DG Inoperable Time Extended Due to Overspeed Trip Problem”
CR 04-04798, “Division 1 DG Turbocharger Oil Pressure Trend”
CR 04-05008, “Maintenance Rule Unavailability Review Based on >75% of the System Limit”
CR 04-05128, “RFA - 1R43C0001B Division 2 Diesel”
CR 04-05267, “Supporting Documentation for DG Building Internal Missile Hazards”
CR 04-05314, “Unanalyzed Condition Postulated for Division 1 and 2 EDGs”
CR 04-05356, “CR 04-03185 Operability Determination Problem Statement Missed
CR 04-03187, "Diesel Exhaust Back Pressure Calculation Adequacy”
CR 04-05385, “RFA - CR to Clarify Back Pressure Requirements on 1R47-F0504B”
CR 04-05389, “Relief Valve 1R47-F0504B Fails Lift Setpoint Test”
CR 04-05400, “Engineering Approval to Use Hardened Washers on Division 2 Left Bank”
CR 04-05403, “PCR-PMI-0047 Removal of Vibration Switch”
CR 04-05407, “Division 1 DG Jacketwater Leak Container Inadequate”
CR 04-05443, “Turbo Charger Tie Plate”
CR 04-05445, “Fuel Oil Drip from Division 2 Diesel Generator Return Header”
CR 04-05454, “Blown Fuse, Division 2 DG Fuel Oil Booster Pump”
CR 04-05460, “Clearance PY1-R43-0035A Incorrectly Hung”
CR 04-05525, “Turbo Lube Oil Sight Glass Flow Is Not Visible”
CR 04-05604, “Relief Valve Failed As-Found Testing and Was Re-installed”
CR 04-06009, “PY-C-04-04: Use of Technical Graffiti Instead of Labels or Stencils”
CR 04-06302, “Audit PY-C-04-04 - Order Did Not Contain Adequate/Approved Direction”
CR 04-06309, “Failure to Notify QC for Witness Point During Bench Test of Removed Relief Valve”
CR 04-06692, “Independent Verification Is Not Required for DC FOBC Testing”
CR 05-00265, “Bushing Found During Division 2 Testable Rupture Disc Rework”
CR 05-00463, “Post Accident Temperature for DG Building Missile Shield Exceeds Design Specification”
CR 05-00515, “Diesel Generator Latent Issue Report Performance Deficiency”
CR 05-00597, “Division 1 and 2 DG Fuel Oil and Lube Oil Vent Lines in DG Missile Shield Enclosure”
CR 05-00754, “PCR for Misleading SOI-R43 P&I”
CR 05-00907, “Division 1 DG TRD Lifted During SVI Run”
CR 05-00922, “NRC Question on Division 1 DG TRD Lift During Normal Run”

CR 05-00936, “Division 2 DG Fail to Quick Restart for SVI-R43-T1348"
CR 05-00944, “Determine the Need to Perform SR 3.8.1.2 for the Division 1 and Division 3 DGs”
CR 05-01000, “Division 2 EDG TRD Reported Lifting During Engine Run”
CR 05-01024, “PII Initiative F Review of CR 03-04912: SOI Instrument Uncertainty Issue”
CR 05-01136, “LCO 3.0.3 Entry Due to Inoperable Testable Relief Devices on Diesel Generators”
CR 05-01114, “DG Governor Replacement Retest Modification Documentation”
CR 05-01207, “Division 1 DG Testable Rupture Disk Lifted During Planned Run”
CR 05-01117, “Division 2 DG Inoperable During 24 Hour Loaded Run”
CR 00-3709, “DG Fuel Oil Strainer Differential Pressure Switch”
CR 03-01078, “RFA - NRC Resident Question Regarding Maintenance Rule Accounting”
CR 03-04374, “Division 2 DG Unplanned Inoperability and Unavailability”
CR 03-04912, “Division 1 Diesel Generator Failed SVI-R43-T1317 Run”
CR 04-00322, “Division 1 and Division 2 Testable Rupture Disc Qualification”
CR 04-02375, “PMI-0058, Add Thrust Bearing Criteria”
CR 04-03013, “Division 1 and 2 DG Exhaust Line Corrosion Latent Issues Review (LIR)”
CR 04-03234, “Diesel Loading in SOI-R43 Differs from Design Basis Loading”
CR 04-03260, “Surveillance Test Requirement Missed”
CR 04-03463, “Division 1 and 2 DG Controls for K1 Relay”
CR 04-03712, “Instrument Root Valves in DG Engine Control Panel Not on VLIs”
CR 04-03768, “Drawing 302-0354-00000, Revision R, Inconsistency”
CR 04-03833, “DG Control Air Supply Filter Do Not Meet System Design Pressure Requirements”
CR 04-04075, “Diesel Fuel Oil Pipe Wear Due to Fretting at Supports, Division ½"
CR 04-04142, “Jacket Water Leakage from Division 1 DG”
CR 04-04170, “RFA Stripped Threads in Electrical Cover”
CR 04-04396, “Diesel Generator Loading Calculation PSTG-0014"
CR 04-05525, “Turbocharger Lube Oil Sight Glass Flow Is Not Visible”
CR 04-06000, “Division 1 and 2 Diesel Generator Latent Issues Review Recommendations”
CR 04-06560, “DG Fuel Oil Strainer Differential Pressure Switch ECR [Engineering Change Request]”
CR 05-00148, “Testable Rupture Disk Lifted Outside LIAZ”
CR 05-00196, “Fretting Observed on Division 2 DG Fuel Oil Piping”
CR 05-01119, “1R48D0014B Did Not Lift Per the Master Setpoint List”
CR 05-01377, “Division 1 DG EGB Null Voltage Drift”
CR 04-06462, “PII Initiative F Review of CR 03-04764: TS 3.5.1.1 ECCS Venting Concern”
CR 04-06500, “PII Initiative F Review of CR 03-04764: RHR Setpoint Calculation Issue”
CR 05-00427, “PIIA-SHR-E12 - Discrepancy Between P&ID, SOI-E12 and SVIs”
CR 05-00523, “PIIA-SHR-E12 - Generic Order Categorization Is Not Consistent”
CR 05-00524, “PIIA-SHR-E12 - Gate Valve 1E12-F0018 Is Being Used as a Throttle Valve”
CR 05-00525, “PIIA-SHR-E12 - Basis for Response to NRC IEN 87-10 Needs to Be Evaluated”
CR 05-00526, “PIIA-SHR-E12 - Historical RHR Lube Oil Samples in Alert/Action Range Not Documented”
CR 05-00528, “RFA PIIA-SHR-RHR GE [General Electric] Recommends RHR, Waterleg Pumps Use Uninterruptible Power”
CR 05-00930, “Discrepancy in LLRT [Local Leak Rate Test] Data Recorded During RFO9 for 1E12F0053A”
CR 05-00958, “PIIA-SHR-E12 - Discrepancies in Curator, SAP, SVIs and Elementary Drawings”

CR 05-00995, “PII-SHR-E12 - 1E12-F031A/B/C and F050A/B PMs Do Not Match the FENOC PM Template”
CR 05-01092, “PIIA-SHR-E12 - 1E12-F055A/B Safety Valves Do Not Meet ASME Code Requirements”
CR 05-01348, “Preset Pins Found Installed in RHR Spring Cans”
CR 03-02402; Div 2 Diesel Generator Did not Field Flash or Develop Output Voltage; April 23, 2003
CR 04-02738; NRC 95002 Inspection Item - Maximum EH Bus Voltage; May 26, 2004
CR 04-06235; Standby Liquid Control System Surveillance Test; November 29, 2004
CR 04-03463; Division 1 and 2 Controls for K1 Relay; July 6, 2004
CR 05-00936; Div 2 DG Fail to Quick Restart for SVI-R43-T1348; February 7, 2005
CR 05-03348; Division 2 DG Experienced Instability During LOOP Test; April 13, 2005
PPDS-3675, "C41-F029A&B failed IST As-found Test Criteria"
PIF 96-2458, "IN 92-18 Evaluation"
CR 96-02989, "C41-F029A&B IST Test Problems"
CR 97-01849, "C41-F029A&B IST Test Problems"
CR 98-02258, "EDG FOST Inspection Results"
CR 99-02286, "C41-F029B failed IST As-found Test Criteria"
CR 00-01527, "Ground Water Intrusion into Level Instrument for Fuel Oil Storage Tank (FOST)"
CR 01-00690, "C41-F029B failed IST As-found Test Criteria"
CR 01-00691, "C41-F029A failed IST As-found Test Criteria"
CR01-03071, "OE Review - NRC IN 2001-13 - Inadequate SLC Relief Valve Margin"
CR 01-03585, "Max Reactor Press. for SLC Pump Acceptance Criteria Could be 27 psi Low"
CR 02-04715, "Flow and Pressure Difficulties while Performing SVI-C41-T2001B"
CR 03-01672, "RFA to Request Expanded Tolerance for Relief Valve"
CR 03-04912, "Division 1 EDG Inoperable during Mode Change"
CR 03-05237, "RFA - Test Requirements for Remote Shutdown Transfer Switch Contacts"
CR 03-05467, "Document "NA" for SOI-R43 following Div 1 EDG Reverse Power Trip"
CR 03-06493, "C61 Transfer Switch Testing"
CR 04-00725, "Procedure Step NA to Allow Pumping of WMT"
CR 04-00754, "QA Audit PY-C-04-01, PAP-0528 Non-Compliance following NA of Procedure Step"
CR 04-00785, "Procedure Step NA during CRD Pump Fill and Vent"
CR 04-00844, "Procedure Step NA during SOI-R22"
CR 04-01149, "PAP-0528 Procedure Use and Adherence Violations Associated with the Use of NA"
CR 04-06235, "PII-SHR-C41 Review, GE Recommendation for Surveillance Test Pressure"
CR 04-06591, "PII-SHR-C41 Setpoint Tolerance Calc for C41-F029 Relief Valve is Excessive"
CR 05-00713, "Incorrect Maximum ATWS Pressure used as Design Input to Calculation C41-008"
CR 05-01027, "PII Initiative "F" Review of 03-4912 Concern with CA-20 Response"
CR 05-01307, "Improper Lubricant Used on MOV"
CR 05-01383, "Use of Never-Seez as an MOV Stem Lubricant"
CR 05-02871, "Identification Tags on CRD HCUs May Interfere with Operation of Scram Valves"
CR 05-02977, "Operating Experience not Screened for Perry Applicability"
CR 05-03103, "Admin Control of Valve Not Established as Required by ECP"
CR 05-03108, "Division 2 EDG Vibration Switches"
CR 05-03111, "Alarm Response Instruction Not Updated as the Result of an ECP"

CR 05-03112, "Remote Shutdown Operation of MOV E12-F011A"
CR 05-03386, "Missing GEI0048 Data Sheet in Work Order 00-2080"
CR 05-03482, "Alarm Response Instruction for H13P-877-1 is incorrect, PCR Correction"
CR 05-03555, "Review the Perry Response to SIL-3"
CR 05-03594, "Failure to Revise a WO Document that Could not be performed as Written"
CR 05-03598, "10CFR50.59 Screening was Not Completed for Calculation EA-0241 rev-0"
CR 05-03686, "Response to CR 04-06235 is Incorrect"
CR 05-03769, "Unable to Locate Test Record for RFO-03 for C41-F029A"
CR 05-03827, "Evaluation Required of Past Operability Based on Revised Calculations"
CR 05-04078, "Need for Fuse Replacement Procedure Guidance Deficiency in IOI-011"
CR 05-04087, "Ineffective Preventative Actions for Root Cause 03-04912"
CR 05-04110, "Appendix-R Exemption for Fuse Replacement not Reflected in USAR"
CR 05-04346, "Control Room Fire Hot Short Item"
CR 05-04462, "Calculation FSPC-0018 Weaknesses"
CR 04-00004, “Fill and Vent Performed Out of Sequence”
CR 02-04025, “RHR Heat Exchanger Minimum Wall Thickness”
CR 02-04491, “Vendor Manual Control Program Identified Weaknesses”
CR 02-04492, “Vendor Manual Program - Generic Letter 90-03, Part (A) Per PY-C-02-04"
CR 02-04716, “RHR B Minimum Flow Valve Dual Indication When Powered Up”
CR 02-04814, “Error Found in Calculation P42-039. Error Was Due to Use of ‘Rule of Thumb’”
CR 03-00493, “Division 3 Diesel Exhaust Rupture Disc Modification”
CR 03-00659, “10CFR50.59 Temporary Alteration Walkdown”
CR 03-00744, “Inspection 2003-002: Modification Design Control Concerns”
CR 03-01458, “Operability Impact of Nonsafety-Related Piping”
CR 03-06261, “Response to OE Results in Inappropriate Changes to Cell Switches”
CR 04-03070, “Hydrotest Pressure on Two Lube Oil Lines Inadequate”
CR 04-03499, “Error in Calculation Supporting an Operability Determination”
CR 05-00670, “03-025 Temporary Alteration Tags Missing”
CR 05-01221, “Results of Perry Engineering Cumulative Assessment: Ineffective Use of CAP [CAP]”
CR 05-01223, “Results of Perry Engineering Cumulative Assessment: Engineering Rigor”
CR 05-01124, “Results of Perry Engineering Cumulative Assessment: Resolve LIR Issues”
CR 05-01225, “Results of Perry Engineering Cumulative Assessment: Use of OE in Plant Health Reviews
CR 05-01353, “RHR Spring Can Issue EPR CR05-01348"
CR 05-01473, “Styrofoam Is Installed in Rattle Space Between Turbine Building and Auxiliary Building at 620' Elevation”

Design Basis & Licensing Documents

FENOC Quality Assurance Program Manual, revision 5
FSAR Section 9.5.1, Revision 12, "Fire Protection System"
FSAR Section 9A, Revision 12, "Fire Protection Evaluation Report"
FSAR Section 15C, Revision 12, "Anticipated Transients Without Scram"
FSAR Change Request 05-015, for FSAR Table 9.3-3
GE-NE-A2200084-44-01, Revision 1, "Analysis - Anticipated Transient without Scram"
NEDE-25518, Dec 1982, "Design Analysis for ATWS Performance"
Perry Operating License NPF-58, amendment 109
Safety Evaluation Report, supplement 3, section 9.5.1.4.2, "Safe Shutdown Capability"

TS 3.8.3 and Bases, "Diesel Fuel Oil"
22A6093AA, Revision 8, "SLC Design Spec Data Sheet"

Apparent/Root Cause Evaluations

CR 02-04542, “RHR A Minimum Flow Valve Found Out of Position”
CR 02-04658, “As Found Data for 1E12F0003B Did Not Meet FTI-F0016 Criteria”
CR 03-03982, “Mis-operation of Instrument and Control Valves”
CR 03-04764, “RHR Waterleg Pump Not Supplying Adequate Pressure”
CR 04-00004, “Fill and Vent Performed Out of Sequence”
CR 05-00930, “PII B - Discrepancy in LLRT Data Recorded During RFO9 for 1E12-F0053A”

NRC Regulatory Documents

Branch Technical Position CMEB 9.5-1, "Guidelines for Fire Protection"
Generic Letter 86-10, "Implementation of Fire Protection Requirements"
Generic Letter 96-01, "Testing of Safety Related Logic Circuits"
IMC 0609, Appendix-F, "Fire Protection SDP"
IMC 0609, Appendix-F, Attachment 2, "Guidance for Fire Degradation Ratings"
IMC 0609, Appendix-F, Attachment 3, "Guidance for Fire Growth and Fire Damage Scenarios"
Information Notice 92-18, "Potential for Loss of Remote Shutdown Capability"
Inspection Procedure 71111.05 Enclosure 2, "Criteria for Fire Protection Manual Actions"
NUREG 0800, "Standard Review Plan 9.5.1, Fire Protection Program"
NUREG 1022, Revision 2, "Event Reporting Guidelines - 10 CFR 50.72 and 50.73"
RIS 2005-07, "Compensatory Measures to Satisfy Fire Protection Program Requirements"

Miscellaneous Documents

F 79 669-2, "Motor Overload Protection for Motor Actuated Valves"
IEEE 741-1997, "Criteria for the Protection of Class 1E Power Systems and Equipment"
IEEE 1290-1996, "Guide for MOV Motor Application, Protection, Control, and Testing"
Limitorque Technical Update 93-03, "Motor Starting Torque at Elevated Temperatures"
Memorandum from S. Morreale to A. Pusateri, "Voltage Limits on 4KV Buses," dated 8-25-2003
OT-3039-010-02, "Operator Training Lesson Plan for OAI-0201"
OE-8842, "Potential for CRD HCU Insert/Exhaust Solenoid Cable/Connector Damage"
RAD 05-01287, Revision 0, "Standby Liquid Control System"
SDM P57, Revision 7, "Safety Related Instrument Air System Description Manual"
SDM B21/N11, Revision 9, "Main Steam System Description Manual"
SIL 3, "Control Rod Drive - Hydraulic Control Unit"
Target Rock Test Record for P.O. 7111576, 76H-012A s/n 8 (C41-F029A), dated 6-26-03
Target Rock Test Record for P.O. 7054334, 76H-012A s/n 4 (C41-F029B), dated 4-4-03
PYPB-PII-002 AI:A.1.2; System Health Review Report Standby Liquid Control (C41); February 28, 2005
PYPB-PII-002 AI:A.1.2; System Health Review Report Reactor Protection System (C71); March 26, 2005
PYPB-PII-002 AI:A.1.2; System Health Review Report Control Rod Drive Hydraulic System (C11B); March 31, 2005
PYPB-PII-002 AI:A.1.3 and A.2.3.1; Cumulative Assessment of the Latent Issues Reviews and System Health Reviews Performed at the Perry Nuclear Power Plant; March 22, 2005

PYPB-PII-002 AI:A.2.2; Division 1 & 2 Diesel Generator Latent Issues Review; January 13, 2005
MPR-2784; Perry Nuclear Power Plant EDG Exhaust Temperature Concerns Past Operability Concerns, Volume 1; Revision 1
MPR-2784; Perry Nuclear Power Plant EDG Exhaust Temperature Concerns Past Operability Concerns, Volume 2; Revision 1
SVI-R10-T5277; Off-Site Power Availability Verification; April 10, 2001
SOI-R43; Division 1 and 2 Diesel Generator System; Revision 21
SOI-E12; Residual Heat Removal System; Revision 21
PAP-1402; Temporary Modification Control; Revision 13
NOP-CC-2003; Engineering Changes; Revision 4
ONI-S11; Unstable Grid; December 18, 2003

<u>Key Attribute - Human Performance</u>

CR 04-00019, “Need to Improve Labeling on Inservice Unit 2 Control Room Meters”
CR 04-00062, “CSR Team Recommendations Relative to CR 03-04764 (Waterleg Pump Air Binding)”
CR 04-00129, “Inconsistent Use of 3 Part Communications”
CR 04-00141, “Diesel Fire Pump Maintenance Order Routed Incorrectly
CR 04-00190, “Trend Review for Adherence to TS Surveillance Instructions”
CR 04-00249, “Loss of LH2A Not Recognized in PWIS”
CR 04-00259, “Turbine Building Heater Bay Stack Flow”
CR 04-00273, “NRC Observations Regarding Procedure Adherence”
CR 04-00311, “SPCU [Suppression Pool Cleanup Pump] Tripped During SOI-E-12 Section 7.12"
CR 04-00316, “Failed ESW Total Flow Channel Check With No Notification”
CR 04-00363, “Calculation SSC-001 Revisions 0, 1, and 2 Not in Curator. Only Calculation Revision 3 in Curator”
CR 04-00423, “Missing Pin on Valve”
CR 04-00466, “Counter-Intuitive Condition Related to P55 Control Panel”
CR 04-00522, “Incomplete Communication from Work Group to Operations”
CR 04-00575, “Failure to Address Inconsistent Test Results”
CR 04-00625, “Inadequate Configuration and Update of Engineering Design Guides”
CR 04-00628, “Fill and Vent Attempted on Component Released for Maintenance”
CR 04-00681, “Lack of Compliance to the Procedure Implementation Process”
CR 04-00727, “Problem with Combined System Lesson Plan Identification”
CR 04-00850, “Poor Communications Between RPs and Control Room”
CR 04-00872, “Breakdown in Communications for Entry Into Offgas Building”
CR 04-01049, “Work Order Process Does Not Maintain Configuration Control”
CR 04-01074, “Data Was Recorded Outside Leave-As-Is Zone During SVI-C51-T0235B”
CR 04-01149, “PAP-0528 Procedure Use and Adherence Violations”
CR 04-01235, “RHR System Flow Value Changed in SOI as a Non-intent Change”
CR 04-01465, “Ineffective CR/CR Investigation Related to Inadequate Thread Engagement”
CR 04-01515, “Collective Significance: Backlog Reduction/Updating Less than Effective”
CR 04-01530, “RFA - Devise New Way to Hang Field Control Switch Safety Tags”
CR 04-01544, “RFA - Label Request for Meters Located on Breakers in Divisional Switchgear”
CR 04-01593, “Incorrect Hook up of MOV [Motor-Operated Valve] Test Switch
CR 04-01628, “Procedure Change Process and the Reactive Approach to Training”

CR 04-01633, “Scheduled Training Missed - Increasing Trend”
CR 04-01637, “Unit 1 Division 3 Battery Room Temperature Problems”
CR 04-01638, “Collective Review of Human Performance Errors in the Maintenance Department”
CR 04-01672, “INPO 2004 AFI - OF.4-1 - SRO Command and Control”
CR 04-01712, “INPO 2004 AFI-ER.7-1 - Weaknesses in Implementation of the Work Management System”
CR 04-01771, “Performance of Hot Work Without Activated Burn Permit”
CR 04-02232, “Audit PY-C-04-02. Procedure Use and Adherence Violation During SVI”
CR 04-02290, “Fire Protection Manning”
CR 04-02444, “Past Maintenance Instruction/Procedure Concerns Not Adequately Addressed”
CR 04-02798, “Division 2 Diesel Lube Oil Cooler Leakage”
CR 04-02888, “Document Stand Down to Discuss Issues Associated with ESW A/B Field Activities”
CR 04-03020, “Potential Training Results Issue Identified During the IP 95002 Inspection”
CR 04-03046, “Additional Kilowatts on the Division 2 Standby Emergency Diesel Generator”
CR 04-03168, “Procedure (SOI-R43) Could Not Be Performed as Written”
CR 04-03490, “Violation of Clearance Tagging Program”
CR 04-03642, “RCIC [Reactor Core Isolation Cooling] Operability Determination Required a Re-Evaluation”
CR 04-04100, “License Class Diagnostic Skill Improvement Action Plan”
CR 04-04915, “3rd Quarter 2004 Continuing Training Not Conducted for Perry NQA Personnel”
CR 04-05220, “Audit PY-C-04-04, OAI-0201 Instruction Non-Compliance”
CR 04-05304, “Housekeeping Needed in the Emergency Core Cooling Rooms”
CR 04-05406, “Red Indicator for Management Observations for Third Quarter 2004"
CR 04-05604, “Relief Valve Failed As-Found Testing and Was Re-installed”
CR 04-05734, “Audit PY-C-04-04, P64 Lesson Plan Contains Inaccurate Information”
CR 04-06018, “Personnel Qualification Program for the Predictive Maintenance Program”
CR 04-06111, “Skills Accreditation Team Finding ACC1-1, Training for Performance Improvement”
CR 04-06302, “Audit PY-C-04-04 - Order Did Not Contain Adequate/Approved Direction”
CR 04-06315, “Audit PY-C-04-04 Inadequate/Incomplete Corrective Action”
CR 04-06462, “PII Initiative F Review of CR 03-04764: TS 3.5.1.1 ECCS Venting Concern”
CR 04-06470, “License Class 03-01 Generic Weaknesses Resulting from JPM [Job Performance Measure] Performance”
CR 04-06472, “PII Initiative F Review of CR 03-04764: Venting Procedure Adequacy Concern”
CR 04-06493, “PII B.1.6 - Training Program for PSA Engineer”
CR 04-06787, “HCU [Hydraulic Control Unit] 2655's EP126 Valve's Soft Seat Was Found Above the Retaining Ring”
CR 05-00374, “Division 3 Diesel TRD Unlatched”
CR 05-00355, “Missed Surveillance Test Item”
CR 05-00633, “Issues Identified During Human Performance Training Pilot”
CR 05-00686, “Nuclear Quality Assurance's Oversight of Programs and Processes”
CR 05-01055, “PII Program Review of Work Management - Training Needs Analysis”

Key Attribute - Procedure Quality

GMI-0017, “Steam Safety Relief Valve Removal and Reinstallation”
TS Amendment 133

GMI-0156, “Operability Test and Maintenance of Diesel Generator Testable Rupture Disc”
ONI-R10 - Flowchart
ONI-SPI A-5, “Division 1 EDG Restoration”
SOI-R43, “Division 1 and 2 Diesel Generator System”
SOI-R45, “Division 1 and 2 Diesel Generator Fuel Oil System”
SVI-R45-T1324, “Division 1 Diesel Generator Day Tank Fuel Oil Water Test”
SVI-B21-T2012, “SRV Uncoupled Stroke Testing”
SOI-E12, “Residual Heat Removal System”
SVI-E12-T1182A, “RHR A LPCI Valve Lineup Verification and System Venting”
SVI-E12-T1182B, “RHR B LPCI Valve Lineup Verification and System Venting”
SVI-E12-T1182C, “RHR C LPCI Valve Lineup Verification and System Venting”
SVI-E12-T2001, “RHR A Pump and Valve Operability Test”
SVI-E12-T2002, “RHR B Pump and Valve Operability Test”
SVI-E12-T2003, “RHR C Pump and Valve Operability Test”
TXI-0367, “Control Room Envelope Air In-Leakage Test”

Key Attribute - Equipment Performance

Work Orders

WO 200001344, “Affix Plastic Deflector Ring to Pump Shaft”
WO 200002011, “Replace Bent Stem”
WO 200002362, “Rework Valve and Actuator if Required”
WO 200002407, “Verify Proper Operation and Positioning”
WO 200002782, “CC - Replace Valve to Eliminate Seat Leakage”
WO 200004801, “Cutout and Replace Solenoid Valves”
WO 200012682, “CC - Rework Oil Leak(s) RHR Waterleg Pump”
WO 200067052, “Troubleshoot/Rework 1E12-R611A Position”
WO 200067053, “Troubleshoot/Rework 1E12-R612A Position”
WO 200082450, “Valve Leaks Past its Closed Seat”
WO 200083752, “CC - Perform a Fill and Vent of the 1R45"
WO 200083772, “Valve Leaks by Seat”
WO 200089204, “Meter Indicator Sticking at 50%”
WO 200100811, “*CC Grease Fitting Needs Replaced”
WO 200103471, “Fuel Oil Indication Won't Pass Channel Check”
WO 200104318, “Replace Motor Sheave Division 2 DG Auxiliary Fan”
WO 200108087, “RTD for Division 1 DG Outboard Generator”
WO 200112206, “Division 1 DG Fuel Oil Sample Valve Leaking”
WO 200116778, “Damaged Flex Conduit”
WO 200118253, “Reroute Internal Wiring”
WO 200118336, “*CC Lube Oil Leak at Fuel Oil Pump Drive”
WO 200118978, “Unit 1 Division 2 Turbo Low Left Bank No Flow”
WO 200120872, “*CC Replace Dresser Couplings on Skid”
WO 200123763, “Division 2 FOST Low Level Alarm Erratic”
WO 200124216, “Oil Leak at 4-way Connection Flange”
WO 200133575, “*CC Fuel Oil Leak LB-8"
WO 200134632, “CC - Replace Pressure Switch”
WO 200135325, “Fuel Oil Leak from Strainer/CR”

WO 200139864, “Leaks at Body Plug”
WO 200139865, “Oil Leak at the Shaft Seal”

Surveillance Testing Results

SVI-E12-T1182A, “RHR A LPCI Valve Lineup Verification and System Venting,” Revision 4, dated 4/25/05
SVI-E12-T1182B, “RHR B LPCI Valve Lineup Verification and System Venting,” Revision 4, dated 4/25/05
SVI-E12-T1182C, “RHR C LPCI Valve Lineup Verification and System Venting,” Revision 4
SVI-E12-T2001, “RHR A Pump and Valve Operability Test,” Revision 20, dated 6/30/05
SVI-E12-T2002, “RHR B Pump and Valve Operability Test,” Revision 20, dated 5/17/05
SVI-E12-T2003, “RHR C Pump and Valve Operability Test,” Revision 18, dated 5/3/05

Post-Maintenance Testing Results

WO 200055789, “LPCS/RHR Waterleg Pump Breaker Test”
WO 200086328, “Head Spray Flow Reads 70 gpm With No Flow”
WO 200007557, “01-13741 - Remove Operator - 1E12-F0040"
WO 200092951, “Relay Was Found Installed Upside Down - 1E12A-K141"
WO 200092963, “CC - Remove and Re-position Relay - 1E12A-K026"
WO 200002665, “01-006330-001 - Fabricate 1E12-F0508A”
WO 200003046, “97-003498-000 Cut Out and Replace Valve - 1E12-F0511A”
WO 200133652, “Verify RHR A Piping Full CR 04-6462"
WO 200133653, “Verify RHR B Piping Full CR 04-6462"
WO 200080962, “Division 1 DG Governor Oil Level <½"
WO 200115289, “CC - Remove Division 1 Diesel Vibration Switch”
WO 200094413, “CC- Inspect Division 1 DG for Installed Oil Plug”
WO 200107425, “CC - Division 1 EDG Fuel Oil Piping”
WO 200115294, “CC - Remove Diesel Vibration Switches”
WO 200139859, “CC- Replace the Division 2 Diesel Generator”
WO 200001345, “Plastic Ring on Pump Shaft Is Loose -1R45C0001A”
WO 200118346, “Blown Fuses on DC Fuel Oil Booster Pump”
WO 200012879, “CC Division 2 Diesel Fuel Oil Supply Pressure -1R45F0562B”
WO 200005656, “03-3221 Sheet Metal Covering Insulation”
WO 200049015, “Perform Cosmetic Grout Repairs - 1R48D0001A”
WO 200040537, “Perform Ultrasonic Thickness Testing -1R48D0001A”
WO 200049030, “Perform Cosmetic Grout Repairs - 1R48D0001B”
WO 200040539, “Perform Ultrasonic Thickness Testing - 1R48D0001B”
WO 200040540, “Perform Ultrasonic Thickness Testing -1R48D0010A”
WO 200040541, “Perform Ultrasonic Thickness Testing - 1R48D0010B”
WO 200105395, “CC ECP 04-0170 - Install New Testable Rupture Disk”
WO 200135848, “Temporarily Unlatch the Testable Rupture Disk”
WO 200135886, “Perform Troubleshooting - 1R48D0014A”
WO 200136757, “CC - Perform Troubleshooting - 1R48D0014A”
WO 200105398, “CC Addendum A-1: Changes Made Due to ECP - 1R48D0014B”
WO 200123236, “CC - Rework/Replace Counterweight Support - 1R48D0014B”
WO 200135832, “*CC - Temporarily Defeat the Testable Rupture Disk - 1R48D0014B”
WO 200135887, “Perform Troubleshooting - 1R48D0014B”

WO 200089279, “Division 2 DG Fan 1B Low Flow”
WO 200116533, “Division 1 DG Room Temperature Indicates Low”

Operating Experience (OE) Information

IN 2003-03, “NRC Information Notice 2003-03, Part 21 - Inadequately Staked Capscrews Renders Residual Heat Removal Pump Inoperable”
OE 19543, “EDG Turbochargers Not Evaluated as Potential Missile Hazard”
OE 19545, “Preliminary - Unanalyzed Back Pressure and Fuel Consumption Conditions Postulated for Emergency Diesel Generators”
OE 18929, “(Preliminary) Reactor Scram While Placing RHR into Shutdown Cooling Mode”
OE 19324, “Update to OE 18929 - Reactor Scram While Placing RHR into Shutdown Cooling Mode”
SOER [Significant Operating Experience Report] 97-01, Re-Review Due to Air Bound LPCS/RHR A Waterleg Pump

Vendor Manual Information

Bingham Williamette Pumps Manual, MRN 9, Revision 11
Rockwell/Edwards Valves Manual, MRN 9, Revision 9
Standby Diesel Generator Manual Volume 1, MRN 27, Revision 25

Key Attribute - Configuration Control

Corrective Maintenance - Non-Outage

WO 200004801 “Cutout and Replace Solenoid Valves - 1E12F0060A”

Elective Maintenance - Non-Outage

WO 200088882, “Unistrut Suspended with Bailing Wire”
WO 200012761, “Perform As-found Testing, Remove Operator -1E51F0022"
WO 200116778, “Damaged Flex Conduit -1E12F0003B”
WO 200134655, “*CC Closed Indication Not Lit -1E51F0022
WO 200003489, “Perform RCIC Turbine Governor Control”
WO 200012744, “CC 02-005976-000 Containment/Drywell Pressure Transmitter - 1C71N0050C”
WO 200069924, “CC - Replace the Division 2 Diesel Generator 1R43C0001B
WO 200089204, “Meter Indicator Sticking at 50% -1R43R0015A”
WO 200108087, “RTD for Division 1 DG Outboard Generator”
WO 200123763, “Division 2 FOST Low Level Alarm Erratic”
WO 200139877, “Division 2 DG Starting Air Right Bank”
WO 200001344, “Affix Plastic Deflector Ring to Pump Shaft - 1R45C0002C”
WO 200002011, “Replace Bent Stem - 1E12F0099B”
WO 200002362, “Rework Valve and Actuator If Required - 1E12F0300C”
WO 200002407, “Verify Proper Operation and Positioning - 1E12F0310"
WO 200002782, “CC - Replace Valve to Eliminate Seat Leakage - 1E12F0074B”
WO 200012682, “CC Rework Oil Leak(s) RHR Waterleg Pump”
WO 200112206, “Division 1 DG Fuel Oil Sample Valve Leaking -1R45F0507A”

WO 200118336, “*CC Lube Oil Leak at Fuel Oil Pump Drive -1R43C0001B”
WO 200120872, “*CC Replace Dresser Couplings on Skid - 1R43C0001B”
WO 200124216, “Oil Leak at 4 Way Connection Flange -1R43C0001A”
WO 200133575, “*CC Fuel Oil Leak LB-8 - 1R43C0001B”
WO 200135262, “*CC Oil Leaks from Various Valve Covers -1R43C0001B
WO 200139864, “Leaks at Body Plug - 1R45F0559A”
WO 200139865, “Oil Leak at the Shaft Seal -1R45C0004B”

Corrective Maintenance - Outage

WO 200011218, “01-017407-000 Contingency Order - 1E12F0084C”
WO 200002653, “01-6330-000 Cut Out and Replace Valve Assembly - 1E12F0508A”

Elective Maintenance - Outage

WO 200094531, “ECP 03-0249 - Replace Orifice - 1E12D0001C”
WO 200007428, “01-013722-000 - Remove Operator”
WO 200078140, “Perform As-Found Testing - 1E12F0053A”

Probabilistic Risk Assessment

DB-003; Unavailability Due to Test and Maintenance; Revision 4
SM-005; System Notebook - Residual Heat Removal System, E12; Revision 3
SM-020; System Notebook - Emergency Diesel Generators; Revision 2
PAP-1924; Risk-Informed Safety Assessment and Risk Management; Revision 4
PYBP-DES-0001; On-Line Risk Assessment Reference Guide; Revision 4
PYBP-POS-0013; Risk-Informed Applications Reference Guide; Revision 0
CR 04-01277; Room Heatup Calculation to Support PSA Model; March 12, 2004
CR 04-01810; Method to Collect PSA Unavailability Data Needs Improvement; March 26, 2004
CR 04-06477; Tracking CR - Need to Revise Calc SQ-001 Impacted By Other Calc Revisions; December 8, 2004
CR 04-06504; PII B.1.6 - Evaluate Usage of Managed Restoration; December 9, 2004
CR 05-03054; Unexpected Valve Strokes During Performance of SVI-R43-T1338; April 2, 2005

Key Attribute - Emergency Preparedness

Procedures

Emergency Plan for Perry Nuclear Power Plant (PNPP), Revision 5, dated August 16, 1985
Emergency Plan for Perry Nuclear Power Plant (PNPP), Revision 22, dated January 20, 2005
EPI-A1, "Emergency Action Levels (EALs)," Revisions 6, dated July 10, 1997
EPI-A1, "Emergency Action Levels (EALs)," Revision 14, dated January 20, 2005
EPI-A2, "Emergency Actions Based Event Classification," Revision 11, dated January 20, 2005
EPI-A6, "Technical Support Center Activation," Revision 15, dated January 20, 2005
EPI-A7, "Operations Support Center Activation," Revisions 12, dated April 29, 2004
EPI-A7, "Operations Support Center Activation," Revisions 13, dated May 14, 2004
EPI-A7, "Operations Support Center Activation," Revisions 15, dated December 22, 2004
EPI-A8, "Emergency Operations Facility Activation," Revision 11, dated December 22, 2004
EPI-B1, "Emergency Notification System," Revision 15, dated January 20, 2005

EPI-C3, "Emergency Preparedness Training," Revision 0, dated September 4, 1986
TMP-2302, "Emergency Plan Training Program," Revision 10, dated June 29, 2004
PSI-0022, "Emergency Plan Training Program," Revision 0, dated March 29, 2005
Procedure Approval Form for EPI-A1, Revision 7, dated November 6, 2003
Procedure Approval Form for EPI-A1, Revision 8, dated March 8, 2004
Procedure Approval Form for EPI-A1, Revision 9, dated March 11, 2004
Procedure Approval Form for EPI-A1, Revision 10, dated June 3, 2004
Procedure Approval Form for EPI-A1, Revision 11, dated August 20, 2004
Procedure Approval Form for EPI-A1, Revision 12, dated September 14, 2004
Procedure Approval Form for EPI-A1, Revision 13, dated September 25, 2004
Procedure Approval Form for EPI-A1, Revision 14, dated January 20, 2005

Assessment Reports

Self-Assessment Report 672RAS2004, "3/18/04 ERO Off-hours Unannounced Drill"
Self-Assessment Report 701RAS2004, "5/11/04 ERO Off-hours Unannounced Drill"
Self-Assessment Report 724PYRC2004, "11/12/04 ERO Off-hours Unannounced Drill"
Self-Assessment of EAL Implementation, dated September 14, 2004
Self-Assessment Report 520PTS2002, "Perry Plant 2002 Emergency Preparedness Evaluated Exercise"
Self-Assessment Report 530PTS2002, “Emergency Response Organization Team ‘B’ Drill”
Self-Assessment Report 531PTS2002, ""Emergency Response Organization Team ‘A’ Drill”
Self-Assessment Report 614RAS2003, "Emergency Response Organization Team ‘C’ Drill”
Self-Assessment Report 625RAS2003, "Emergency Response Organization Team ‘B’ Drill”
Self-Assessment Report 642RAS2003, "Emergency Response Organization Team ‘A’ Drill”
Self-Assessment Report 651RAS2004, "Emergency Response Organization Team ‘C’ Drill”
Self-Assessment Report 673RAS2004, "Emergency Response Organization Team ‘B’ Drill”
Self-Assessment Report 713RAS2004, "Emergency Response Organization Team ‘A’ Evaluated Exercise”
Self-Assessment Plan PYRC2005, "ERO Off-Hours Unannounced Drill"
Self-Assessment Report 759PYRC2005, "ERO Off-Hours Unannounced Drill
September 2004 Perry Nuclear Power Plant Evaluation Report, Emergency Preparedness Consulting, September 13-17, 2004
Perry Nuclear Quality Assessment Quarterly Audit Report PY-C-02-02, dated August 15, 2002
Perry Nuclear Quality Assessment Quarterly Audit Report PY-C-02-04, dated February 17, 2003
Perry Nuclear Quality Assessment Quarterly Audit Report PY-C-03-01, dated April 18, 2003
Perry Nuclear Quality Assessment Quarterly Audit Report PY-C-03-02, dated August 26, 2003
Perry Nuclear Quality Assessment Quarterly Audit Report PY-C-03-03, dated November 26, 2003
Perry Nuclear Quality Assessment Quarterly Audit Report PY-C-03-04, dated March 5, 2004
Perry Nuclear Quality Assessment Quarterly Audit Report PY-C-04-01, dated April 30, 2004
Perry Nuclear Quality Assessment Quarterly Audit Report PY-C-04-02, dated August 20, 2004
Perry Nuclear Quality Assessment Quarterly Audit Report PY-C-04-03, November 20, 2004

Condition Reports

CR 02-03576, “Deficiencies in Emergency Plan Requal Training”
CR 03-01190, “Issue of Off-hours Drills and Site Access by ERO Responders”

CR 04-01244, “Two EAL Changes Made in 1998 Should Have Been Submitted to NRC for Approval Prior to Implementation”
CR 04-01404, “March 18, 2004 Off-hours Unannounced Drill”
CR 04-03356, “NQA Assessment PY-C-04-02"
CR 04-03986, “Decision Process to Enter EAL HA1 During 7/20/04 Alert”
CR 04-03987, “Failure to Perform CADAP Run During 7/20/04 Alert”
CR 04-04824, “Self-assessment of EAL Implementation Identified Three EALs with Missing Logic "And" Connectors”
CR 04-04825, “Observations and Recommendations During EAL Implementation Self-Assessment”
CR 04-04827, “EAL Change to GA2 May Have Been Made Without DIE Review”
CR 05-02515, “Emergency Plan, Table 5-1 May Need Clarification Regarding On-Shift Staffing”
CR 05-02664, “Conflict in the Text Versus Table 5-1 of the E-Plan, Revision 5"
CR 05-03271, “Documentation Deficiencies Concerning Off-hours Augmentation Drills”
CR 05-03659, “Deficiency in NOBP-LP-1651, ‘Security Event Checklists’”
CR 05-03681, “ERO Emergency Coordinator Interviews During 95003 Inspection”
CR 05-03685, “Incorrect Attachment 1 to Procedure EPI-A7, ‘Operations Support Center Activation’”

Inspection Procedure 95002 Review Activities

Condition Reports

CR 04-03026, “NRC 95-002 Inspection: QC Inspection Did Not Comply with ANSI N45.2.8"
CR 05-02617, “Disassembly of the Division I and II Emergency Service Water Pumps”
CR 05-02547, “GMI [General Maintenance Instruction] 0039 & 0040, ESW Pump Disassembly/ Reassembly Procedure”
CR 05-02474, “Emergency Service Water Pump A”
CR 04-02876, “Cumulative Significance Review of All Conditions Reports for the ESW A & B Pumps”
CR 04-02598, “ESW Pump A Failure”
CR 04-06462, “PII Initiative F Review of CR 03-004764; TS 3.5.1.1 ECCS Venting Concern”
CR 05-02060, “PII F Team Review: Piping Venting Concerns Related to CR 04-06462 Response”
CR 04-06111, “Skills Accreditation Team Finding ACC1-1, Training for Performance Improvement”
CR 04-03020, “Potential Training Results Issue Identified During the 95002 Inspection”
CR 04-04059, “Site Human Performance Barriers Maybe Lost During Stressful Times”
CR 04-03105, “Violation of Criterion XVI Identified During 95002 Inspection”
CR 04-04917, “OE 18987 Review Indicates Possible Air Void in Abandoned RHR Piping to RCIC Suction Pipe”
CR 04-01688, “INPO 2004 AFI OR.3-1- Perform Shortfalls in Individual & Organization Behaviors”
CR 05-03126, “Procedural Compliance Review for ARCs Associated with ECP 05-0032"
Hold/Witness Waiver Log; May 1, 2005 through April 6, 2005
Inspection Notification Log; March 3, 2005 through April 8, 2005
CR 04-06627, “Audit PY-C-04-04- QC Did Not Assign H/W [Hold/Witness] Points in ESW Order”
CR 05-03130, “Three EDGs Inoperable”

CR 05-02676, “Common Theme of Procedure Non-Compliance Identified at 95003 Phase B Debrief”
CR 05-02868, “At Risk ECP Implementation for Division 1 Diesel Exhaust Flow Path”
CR 02-03972, “HPCS Pump Failed to Start”
CR 03-04764, “RHR-A/LPCS Water-Leg Pump, not Supplying Adequate Pressure”
CR 03-05065, “ESW Pump Failed”
CR 04-02598, “ESW Pump A Failure”
PYBP-PII-0002, “Perry Nuclear Power Plant PII Detailed Action and Monitoring Plan,” Revision 3

Procedures

NQI-1003; Control of Inspection Plans; Revision 0
NQI-1001; QC Inspection Program Control; Revision 4
GMI 0039, “Disassembly/Reassembly of Division 1 and II Emergency Service Water Pumps,” Revisions 11 through 17
NOP-CC-2003, “Engineering Changes,” Revision 4
NOP-CC-2003, “Engineering Changes,” Revision 5
CMI-0018, “Division I/II Emergency Diesel Generator Cylinder Liner Honing,” Revision 2

Work Orders

WO 200144465, PY-1P45 Emergency Service Water Pump; dated March 28, 2005
WO 200112207, PY-1P45 Emergency Service Water Pump; dated March 24, 2005
WO 200082292, PY-1E21 Low Pressure Core Spray, dated April 6, 2005

Miscellaneous

Project Plan for Maintenance Procedures Upgrade Associated with Key Critical Components; dated November 20, 2004
Quality Assurance Program Manual, Revision 5
Root Cause Report 03-05065, Revision 1 - ESW Pump Coupling Failure
Root Cause Report 04-02598, Revision 0 - ESW Pump Coupling Repeat Failure
Common Cause Analysis Report & Organizational Effectiveness Improvement Initiative, dated September 28, 2004

Perry PII Review

PII - Scope Review

Common Cause Analysis Report and Organizational Effectiveness Improvement Initiative, Revision 2 - Condition Report 03-05995
Root Cause Report 02-03972, Revision 4 - High Pressure Core Spray Pump Failure to Start
Root Cause Report 03-04764, Revision 1 - Low Pressure Core Spray/Residual Heat Removal Waterleg Pump Air Binding
Root Cause Report 03-04912, Revision 1 - Division 1 Emergency Diesel Generator Inoperable During Mode Change
Root Cause Report 03-05065, Revision 1 - ESW Pump Coupling Failure
Root Cause Report 04-02598, Revision 0 - ESW Pump Coupling Repeat Failure

One copy of additional root cause reports reviewed to develop Revision 1 to the PII
Detailed list by number, title, and date of documents reviewed to develop Revision 2 to the PII
CR 04-01145, “Organizational Behavior Issues Results in Untimely Resolution of Equipment Issues - Collective Significance Design Information”
CR 04-01514, “Collective Significance Backlog Reduction Updating Less Than Effective”
CR 04-01694, “Configuration Management - Timely Resolution of Issues Involving Conformance to Design”
CR 04-01689, “Safety System Reliability and Availability”
CR 04-01683, “Organizational Effectiveness to Standards and Accountability”
CR 04-01688, “Performance Shortfalls in Individual and Organizational Behaviors”
Self-Assessment 637PIU2004 - Corrective Action Implementation
PYPB-PII-005, "Closure and Validation of PII Actions

PII - Implementation Review

Equipment Performance and Configuration Plan

PNPP Performance Improvement Equipment Performance and Configuration Initiative, Revision 2, dated January 6, 2005
PYBP-PNED-0002, Revision 0, Perry Nuclear Engineering Department System Health Review
PYBP-PNED-0003, Revision 0, Perry Nuclear Engineering Department Latent Issues Review
755P112005 Self Assessment Cumulative Assessment of the Latent Issues Review and System Health Reviews Performed at PNPP, dated February 2005

Program/Procedure Review Initiative

PNPP PII, “Program/Procedure Review Initiative,” Revision 1, dated November 16, 2004
PYBP-PII-0003, Revision 1, “PII Program Review Process”
727PYDM2005, “Configuration Management Program Self Assessment”
PNPP PII Program/Procedure Reviews, Configuration Management Program, Action B1.1, dated October 2004
732PYOP2005, “On-Line Risk Management Program Self-Assessment”
PNPP PII, Program/Procedure, On-Line Risk Management Program, Action B.1.6, Revision 0, dated October 2004
733PYOP2005, “Operability Determination Program Self-Assessment”
PNPP PII, Program/Procedure, Operability Determination Program, Action B.1.7, Revision 0, dated October 2004
736PYTM2005, “Human Performance Program Self-Assessment”
PNPP PII, Program/Procedure, Human Performance Program, Revision 0, Action B1.1.10, dated October 2004
737PYRC, “Emergency Preparedness Program Self-Assessment”
PNPP PII, Program/Procedure, Emergency Preparedness Program Review Implementation Plan, Revision 0, Action B.1.11, dated October 2004
Project Plan for Maintenance Procedures Upgrade Associated with Key Critical Components, Revision 1, dated November 20, 2004
PYBP-PII-0002; PII Detailed Action and Monitoring Plan - On-line Risk Program; Revision 3

Containment and Safety Systems Plan

PNPP Work Plan, Revision 0, “Containment Upgrade Project”
ECR 04-0092
ECR 04-0092-A

Corrective Action Implementation Improvement Plan

PNPP PII, “CAP Implementation Initiative,” Revision 1, dated December 29, 2004
CR 04-02404 Operating Experience Program/Implementation Issues Identified During Assessment; dated 5/12/04
CR 04-02468 Quality Assessment PY-C-04-01 Rated Corrective Action Program as Marginal; dated 4/23/04

Organizational Effectiveness Improvement Plan

Organizational Effectiveness Improvement Initiative, dated December 2004
Training Improvement Plan

Validations of Root Cause Actions and Effectiveness Review of Root Cause Corrective Actions

PNPP PII, “Validation of Root Cause Actions and Effectiveness Review of Root Cause Corrective Actions,” Revision 2, dated December 16, 2004
CR 03-04764 RHR-A/LPCS Water-Leg Pump Not Supplying Adequate Pressure; dated 8/14/03
CR 03-04912 Division 1 Diesel Generator Failed SVI-R43-T1317 Run; dated 8/21/03

LIST OF ACRONYMS USED

AFI	area for improvement
ANS	American National Standard
ANSI	American National Standards Institute
ARC	at-risk-change
ARI	Alarm Response Instruction
ASME	American Society of Mechanical Engineers
ATWS	anticipated transient without scram
BWR	boiling water reactor
CADAP	Computer Aided Dose Assessment Program
CAQ	condition adverse to quality
CAP	Corrective Action Program
CARB	Corrective Action Review Board
CFR	*Code of Federal Regulations*
CR	condition report
CRDH	control rod drive hydraulic
CST	condensate storage tank
CVDWP	containment vessel and drywell purge
DBD	Design Basis Document
DG	diesel generator
DIE	decrease in effectiveness
DWC	drywell cooling
EAL	emergency action level
EC	Emergency Coordinator
ECCS	emergency core cooling system
ECCW	emergency closed cooling water
ECP	Engineering Change Package
ECR	Engineering Change Request
EDG	emergency diesel generator
EOF	Emergency Operations Facility
ENS	Event Notification System
EP	Emergency Preparedness
EPIP	Emergency Plan Implementing Procedure
EPRI	Electric Power Research Institute
ERO	Emergency Response Organization
ESW	emergency service water
FAC	flow accelerated corrosion
FENOC	FirstEnergy Nuclear Operating Company
FIN	Finding
FME	foreign material exclusion
FPCC	fuel pool cooling and cleanup
FSAR	Final Safety Analysis Report
GE	General Electric
GMI	General Maintenance Instruction
HCU	hydraulic control unit
HP	Health Physics
HPCS	high pressure core spray
HVAC	heating, ventilation, and air conditioning

I&C	instrumentation and control
IDCN	Interim Drawing Change Notice
IEEE	Institute of Electrical and Electronics Engineers
IGSCC	intergranular stress-corrosion cracking
IMC	Inspection Manual Chapter
INPO	Institute for Nuclear Power Operations
IP	Inspection Procedure
IOI	Integrated Operating Instruction
IR	Inspection Report
IRM	intermediate range monitor
ISI	Inservice Inspection
IST	Inservice Testing
JFG	Job Familiarization Guideline
JIT	Just-in-Time
KV	kilovolt
KW	kilowatt
LER	Licensee Event Report
LLRT	Local Leak Rate Test
LOOP	loss of offsite power
LPCI	low pressure coolant injection
LPCS	low pressure core spray
MOV	Motor-Operated Valve
MPFF	maintenance preventable functional failure
MSIV	Main Steam Isolation Valve
N/A	Not Applicable
NCAQ	conditions not adverse to quality
NCC	Nuclear Closed Cooling
NCV	Non-Cited Violation
NLO	non-licensed operator
NMCA	Noble Metals Chemical Application
NOUE	Notification of Unusual Event
NOV	Notice of Violation
NQA	Nuclear Quality Assurance
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
OA	Operations Advisor
OD	operability determination
OE	Operating Experience
OM	Operations Manager
ONI	Off-Normal Instruction
OSC	Operations Support Center
OSCC	Operations Support Center Coordinator
PCIV	Primary Containment Isolation Valve
PI	Performance Indicator
PIF	Problem Identification Form
PII	Performance Improvement Initiative
PM	preventative maintenance
PNPP	Perry Nuclear Power Plant
PRA	probabilistic risk assessment

PSA	probabilistic safety assessment
psig	pounds per square inch gauge
QA	Quality Assurance
QC	Quality Control
RCIC	reactor core isolation cooling
RCIS	Rod Control and Information System
RCS	Reactor Coolant System
RFA	Request For Assistance
RFO	Refueling Outage
RHR	residual heat removal
RP	Radiation Protection
RPS	reactor protection system
RSP	remote shutdown panel
RSPS	risk-significant planning standard
RWCU	reactor water cleanup
SAE	Site Area Emergency
SCAQ	significant condition adverse to quality
SCWE	safety conscious work environment
SDP	Significance Determination Process
SHR	System Health Review
SIL	Service Information Letter
SLC	standby liquid control
SM	shift manager
SOI	System Operating Instruction
SSC	structure, system, or component
SSCR	Safe Shutdown Capability Report
SSS	security shift supervisor
SVI	Surveillance Instruction
TE	Technical Engineer
TRD	testable rupture disk
TS	Technical Specification
TSC	Technical Support Center
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
V	volt
VAC	volts alternating current
WO	work order