NRC FORM 464 Part I
(6-1998)

U.S. NUCLEAR REGULATORY COMMISSION

RESPONSE TO FREEDOM OF INFORMATION ACT (FOIA) / PRIVACY ACT (PA) REQUEST

FOIA/PA	RESPONSE NUMBER
2001-0026	1

RESPONSE TYPE ☑ FINAL ☐ PARTIAL

REQUESTER: James V. Vassello

DATE: NOV 06 2000

PART I. – INFORMATION RELEASED

- ☐ No additional agency records subject to the request have been located.
- ☐ Requested records are available through another public distribution program. See Comments section.
- ☐ APPENDICES: Agency records subject to the request that are identified in the listed appendices are already available for public inspection and copying at the NRC Public Document Room.
- ☑ APPENDICES: A — Agency records subject to the request that are identified in the listed appendices are being made available for public inspection and copying at the NRC Public Document Room.
- ☑ Enclosed is information on how you may obtain access to and the charges for copying records located at the NRC Public Document Room, 2120 L Street, NW, Washington, DC.
- ☐ APPENDICES: Agency records subject to the request are enclosed.
- ☐ Records subject to the request that contain information originated by or of interest to another Federal agency have been referred to that agency (see comments section) for a disclosure determination and direct response to you.
- ☐ We are continuing to process your request.
- ☐ See Comments.

PART I.A -- FEES

AMOUNT *: $

* See comments for details

- ☐ You will be billed by NRC for the amount listed.
- ☐ You will receive a refund for the amount listed.
- ☑ None. Minimum fee threshold not met.
- ☐ Fees waived.

PART I.B -- INFORMATION NOT LOCATED OR WITHHELD FROM DISCLOSURE

- ☐ No agency records subject to the request have been located.
- ☐ Certain information in the requested records is being withheld from disclosure pursuant to the exemptions described in and for the reasons stated in Part II.
- ☐ This determination may be appealed within 30 days by writing to the FOIA/PA Officer, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001. Clearly state on the envelope and in the letter that it is a "FOIA/PA Appeal."

PART I.C COMMENTS (Use attached Comments continuation page if required)

As requested, the released records are being placed in our Public Document Room. The records are expected to be available through the NRC's Public Electronic Reading Room, under the above FOIA/PA-2001-0026, at http://www.nrc.gov/NRC/ADAMS/index.html approximately 1 week from the date of this response. If you need assistance in obtaining any publicly available information, you may contact the PDR at 301-415-4737, or 1-800-397-4209.

SIGNATURE - FREEDOM OF INFORMATION ACT AND PRIVACY ACT OFFICER

Carol Ann Reed

Re: FOIA 01-026

APPENDIX A
RECORDS BEING RELEASED IN THEIR ENTIRETY
(If copyrighted identify with *)

NO.	DATE	DESCRIPTION/(PAGE COUNT)
1.	01/28/00	Letter from T. Kozak to J. Wood re: Perry Inspection Report 50-440/99014(DRP) (18 pages)
2.	03/09/00	Letter from T. Kozak to to J. Wood re: Perry Inspection Report 50-440/99015(DRP) (63 pages)

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
801 WARRENVILLE ROAD
LISLE, ILLINOIS 60532-4351

January 28, 2000

Mr. John K. Wood
Vice President - Nuclear
FirstEnergy Nuclear Operating Company
P.O. Box 97, A200
Perry, OH 44081

SUBJECT: PERRY INSPECTION REPORT 50-440/99014(DRP)

Dear Mr. Wood:

On January 5, 2000, the NRC completed a routine safety inspection at the Perry Nuclear Power Plant. The enclosed report presents the results of that inspection.

During this inspection period, the overall conduct of activities at the Perry facility was conservative, with continuing focus on safety. Routine maintenance and surveillance testing activities were properly coordinated and performed per approved procedures. Engineering department personnel generally provided good support to maintenance and test activities and appropriately addressed operability questions. However, the inspectors identified one instance where a licensed operator appeared to be inattentive to his duties. An immediate investigation by your staff determined that the operator was tired but was fit for duty. As a conservative action, the operator was reassigned to the operations foreman position. The review of this issue by your staff was thorough and lessons learned were effectively promulgated to plant personnel.

Based on the results of this inspection, the NRC has determined that one violation of NRC requirements occurred. This violation, which concerns the use of an inadequate tagout to support a maintenance activity, is being treated as a Non-Cited Violation (NCV), consistent with Section VII.B.1.a of NRC's Enforcement Policy. This NCV is described in the inspection report. If you contest the violation or severity level of the NCV, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001, with copies to the Regional Administrator, Region III, and the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be placed in the NRC Public Document Room.

Sincerely,

Thomas J. Kozak, Chief
Reactor Projects Branch 4

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

Enclosure: Inspection Report 50-440/99014(DRP)

cc w/encl: G. Dunn, Manager, Regulatory Affairs
R. Schrauder, Director, Nuclear Engineering Department
W. Kanda, General Manager Nuclear Power Plant Department
N. Bonner, Director, Nuclear Maintenance Department
H. Bergendahl, Director Nuclear Services Department
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U. S. NUCLEAR REGULATORY COMMISSION
REGION III

Docket No:	50-440
License No:	NPF-58
Report No.:	50-440/99014(DRP)
Licensee:	FirstEnergy Nuclear Operating Company P.O. Box 97 A200 Perry, OH 44081
Facility:	Perry Nuclear Power Plant
Location:	Perry, OH
Dates:	November 16, 1999, through January 5, 2000
Inspectors:	C. Lipa, Senior Resident Inspector R. Vogt-Lowell, Resident Inspector D. Chyu, Reactor Engineer S. Burton, Senior Resident Inspector, Monticello P. Lougheed, Reactor Engineer
Approved by:	Thomas J. Kozak, Chief Reactor Projects Branch 4

EXECUTIVE SUMMARY

Perry Nuclear Power Plant
NRC Inspection Report 50-440/99014(DRP)

This inspection report included resident inspectors' evaluations of aspects of licensee operations, engineering, maintenance, and plant support activities.

Operations

- The inspectors identified one instance where the At-the-Controls operator appeared to be inattentive to duty. The licensee promptly initiated an investigation and determined that the operator was tired but was fit for duty. As a conservative action, the operator was reassigned to the operations foreman position. The licensee's review of this issue was thorough and lessons learned were effectively promulgated to plant personnel (Section O1.1).

- The licensee identified that inattention-to-detail during the preparation and review of a tagout led to the use of an inadequate tagout for an electrical relay that was to be replaced. Through the investigation, the licensee determined that there had been several other tagout issues in the past year and initiated a collective significance review of these issues. This was a non-cited violation (Section O1.3).

Maintenance

- Maintenance and surveillance activities observed were adequately planned and executed in the field without an adverse impact on plant operations. Pre-job briefings were thorough and activities were properly coordinated between departments and performed according to approved procedures (Section M1.5).

Engineering

- The licensee identified that repetitive failures of emergency diesel generator turbo charger bolts had occurred over the past year. However, this condition was not thoroughly evaluated in the initial operability determination. For example, the seismic qualification of the EDG, the effect of additional vibrations due to the loose/broken bolts, and the possibility for a common mode failure cause were not initially evaluated. It was determined during a subsequent evaluation that the diesel was seismically qualified, the purpose of the bolts was to assist in dampening vibrations, and that the EDG was operable because additional vibrations would not be of sufficient magnitude to impact continued diesel operation (Section E1.1).

Report Details

Summary of Plant Status

At the beginning of this inspection period, the plant was being operated at 100 percent power. From December 16 until December 18, 1999, the licensee reduced power to 98 percent until an evaluation was completed of the feedwater temperature compensation issue (Section O2.2). On December 31, 1999, the licensee reduced power to 85 percent as part of preparations for the year 2000 rollover. Power was increased to 100 percent, beginning at 10:00 a.m. on January 1, 2000. The plant was operated at approximately 100 percent for the remainder of the period.

I. Operations

O1 Conduct of Operations

O1.1 Operator-at-the-Controls Inattentive to Duties

a. Inspection Scope

The inspectors followed the guidance of IP 71707 in touring the control room and discussing the plant status with control room operators.

b. Observations and Findings

On November 30, 1999, an inspector observed that the At-The-Controls (ATC) operator appeared to be inattentive to his duties. This issue was brought to the attention of the Unit Supervisor (US). An immediate investigation was conducted and it was determined by the licensee that the operator was tired but was fit for duty. As a conservative measure, the ATC operator was reassigned to the operations foreman position. The US and Shift Supervisor (SS) discussed the situation with the operations manager and the plant manager and a CR (99-2972) was initiated to investigate.

The investigation team was thorough and interviewed numerous personnel. During the investigation, it was determined that this was an isolated case and that there were no other instances of operators appearing to be inattentive to duty identified in the control room. Early during the shift in question, the operators were very busy and the ATC operator was attentive and involved in testing activities. As the shift progressed, the operator became fatigued but did not report this to his management. A member of another crew who was in the control room for training had noticed and mentioned to the ATC operator that he appeared tired but this was not raised further. The licensee captured these observations and effectively promulgated lessons learned to plant personnel.

c. Conclusions

The inspectors identified one instance where the licensed Operator-at-the-Controls appeared to be inattentive to duty. The licensee promptly initiated an investigation and determined that the operator was tired but was fit for duty. As a conservative action, the operator was reassigned to the operations foreman position. The licensee's review of this issue was thorough and lessons learned were effectively promulgated to plant personnel.

O1.2 Onsite Inspector Activities for Year 2000 Rollover

a. Inspection Scope (71707)

The inspectors followed the guidance of IP 71707 and CPIP 500 in reviewing onsite activities during the Year 2000 rollover.

b. Observations and Findings

As specified in CPIP 500, one inspector was on site from 10 p.m. on December 31, 1999, until 6 a.m. on January 1, 2000. The inspector was in the control room continuously from 11 p.m. until 1:20 a.m. and at other times throughout the shift. The inspector observed that the control room staff was attentive to electrical grid voltage and frequency indications and prepared for the potential that the plant could scram if a grid disturbance occurred. There were no grid disturbances, no plant transients, and no equipment challenges during the shift.

O1.3 Inadequate Tagout Provided for Electrical Maintenance Activity

a. Inspection Scope (62707, 71707)

The inspectors followed the guidance of IP 62707 and 71707 in reviewing a licensee-identified issue associated with a tagout for the annulus exhaust gas treatment system (AEGTS). The inspectors reviewed the applicable procedures, tagout documents, and the licensee's investigation.

b. Observations and Findings

On November 9, 1999, electrical maintenance technicians identified that an inadequate clearance (tagout) had been prepared to support a maintenance activity on the AEGTS system. The requested tagout was expected to remove all power sources to an AEGTS electrical relay; however, the technicians found voltage at the relay contacts as they prepared to begin work. Work was suspended until the condition was investigated under CR 99-2705.

The licensee's investigation identified that Tagout # 32639, prepared to support the maintenance activity associated with Work Order (WO) 99-11669, was inadequate. The tagout de-energized only the relay solenoid, but it should have de-energized both the relay solenoid and relay contacts since there was still voltage to the relay contacts through an alarm circuit. During the technician's pre-job walkdown, he checked for

voltage to verify that the tagout was properly hung and identified this discrepancy. The cause of the inadequate tagout was determined to be inattention-to-detail on the part of the tagout preparers and reviewers. The tagout preparers and reviewers failed to identify that the source of voltage to the relay's contacts was not isolated by de-energizing the relay solenoid. Plant Administrative Procedure PAP-1401, "Clearance/Tagout Program," Revision 9, required that clearances shall provide 1 mechanical break for work on circuits less than or equal to nominal 480 volts. This procedure was not followed when the tagout did not provide a mechanical break for the circuit associated with the relay contacts.

During the investigation, the licensee determined that a corrective action implemented to address previous problems with tagouts was no longer in place. As a result of weaknesses identified through investigation of Potential Issue Form (PIF) 97-2245, a corrective action was to have personnel with electrical expertise assigned to the tagout team. A person had been assigned to this position on a rotational assignment, but when his rotation ended, the position was left unfilled due to resource limitations. This condition was subsequently corrected on January 3, 2000 by a corrective action assigned as a result of CR 99-2705.

The investigation under CR 99-2705 also reviewed other recent tagout-related issues. In the past year, there were 4 other instances where inadequate tagouts were prepared. Also, there were 26 other examples associated with administrative controls or weaknesses in the implementation of the program. A more extensive collective significance review of these related issues was planned to be completed by February 20, 2000, as a remedial action for CR 99-2705.

Technical Specification (TS) 5.4.1.a requires that procedures listed in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978 be implemented. A procedure for Equipment Control (e.g., locking and tagging) is listed in this Appendix. The failure to properly implement PAP-1401 is a violation of TS 5.4.1.a. This Severity Level IV violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as CR 99-2705. **(NCV 50-440/99014-02)**

c. Conclusions

The licensee identified that inattention-to-detail during the preparation and review of a tagout led to the use of an inadequate tagout for an electrical relay that was to be replaced. Through the investigation, the licensee determined that there had been several other tagout issues in the past year and initiated a collective significance review of these issues. This was a non-cited violation

O2 Operational Status of Facilities and Equipment

O2.1 General Plant Tours and System Walkdowns (71707)

The inspectors followed the guidance of IP 71707 in walking down accessible portions of several systems and areas, including:

- Hydraulic control units
- Control complex
- Containment building
- Turbine building/heater bay
- High pressure core spray system
- Switchgear and station battery rooms
- Emergency diesel generator
- Remote shutdown panel

Equipment operability, material condition, and housekeeping were acceptable in all cases. The inspectors identified no substantive concerns as a result of these walkdowns.

O2.2 Disabled Feedwater Temperature Compensation

a. Inspection Scope (71707)

The inspectors followed the guidance of IP 71707 and reviewed the circumstances associated with a December 16, 1999 licensee event notification required by Section 2.F of the Perry Operating License.

b. Observations and Findings

Section 2.C.(1) of the Perry Operating License authorizes the licensee to operate the facility at reactor core power levels not in excess of 3579 megawatts thermal (MWt). Section 2.C.(2) of the Perry Operating License, requires, in part, that the facility be operated in accordance with the TS. Section 2.F of the Perry Operating License requires the licensee to report any violations of the requirements contained in Section 2.C of the Operating License to the NRC Operations Center.

As a result of the above requirements, at 1903 hours on December 16, 1999, the licensee reported that during the preceding operating cycle, the Perry Plant potentially exceeded its rated power level. It appears that implementation of a General Electric software change contained within the Cycle 7 core reload design information had disabled the feedwater temperature compensation. Upon this discovery, the licensee immediately imposed a 2 percent power reduction at 1349 hours on December 16, 1999, until feedwater temperature compensation could be restored. Restoration was accomplished and power was returned to 100 percent at 0147 hours on December 18, 1999.

Feedwater flow is a dominant factor in the accurate determination of reactor thermal power. The feedwater flow instrumentation is calibrated for a feedwater temperature of 420 °F. Any feedwater temperature other than 420 °F requires correction of the measured flow based on the variation from 420 °F to arrive at the actual flow. At feedwater temperatures above 420 °F, the calculated reactor thermal power is greater than the actual (i.e., conservative) and at feedwater temperatures below 420 °F, the calculated reactor thermal power is less than the actual (i.e., nonconservative). At 100 percent power, with normal feedwater heating, the plant operates at approximately 421.5 °F, and the calculated reactor thermal power is slightly higher than the actual, and

is therefore conservative. However, if the plant is operated at an indicated 100 percent power level with reduced feedwater heating, the potential exists to exceed 100 percent of licensed power level.

The licensee's preliminary investigations indicate that during cycle 7, plant operation exceeded the licensed power level of 3579 MWt, as well as the core transient analysis limit of 102 percent of 3579 MWt towards the end of the cycle when feedwater heaters were removed from service with the plant remaining at an indicated power level of 3579 MWt. In addition, this may have resulted in improper APRM channel calibrations. Initial estimates are that the plant was operated at 102.4 percent of 3579 MWt.

To document and investigate the problem, the licensee issued a Category 1 condition report (CR 99-3133) and is conducting a root cause investigation. Although there are no current safety concerns with the adequacy of the core thermal power calculation, the inspectors will conduct a further review of the licensee's investigation of CR 99-3133 once it is finalized. This item will be tracked as an Unresolved Item **(URI 50-440/99014-01(DRP))**.

c. Conclusions

Upon discovery of disabled temperature compensation in the core thermal power calculation, the licensee immediately imposed a 2 percent power reduction until the temperature compensation could be restored. Once the proper temperature compensation constants were restored, power was returned to 100 percent. Although there are no current safety concerns with the adequacy of the core thermal power calculation, the inspectors will conduct a further review of the licensee's investigation once it is finalized. This item will be tracked as an Unresolved Item.

O7 Quality Assurance in Operations

O7.1 Licensee Self-Assessment Activities (71707)

During the inspection period, the inspectors reviewed multiple licensee self-assessment activities, including:

- Corrective Actions Review Board (CARB), January 5, 2000
- Daily Manager Meeting - review of new CRs

The CARB reviewed the investigations and proposed corrective actions for several Category 2 CRs and one Category 1 CR. The level of discussion and dialogue amongst board members, elicited by the presentation of investigation results, was suitable to the issues presented. The discussion of new CRs at the Daily Manager Meeting continued to be an effective means of communicating the issues associated with the new CRs to the management team. The inspectors concluded that the self-assessment activities observed were effective.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Review of Routine Maintenance and Surveillance Activities

The inspectors observed or reviewed all or portions of the following work activities:

- SVI-E31-T5312-B, "Turbine Building Main Steam Line Temperature High Channel Calibration for 1E31-N361B and 1E31-N361C"
- WO 98-3108 (T/O #32252), "Inspect, test, repair P43B0001A Heat Exchanger"
- PTI-E12-P0003, "RHR Heat Exchangers B and D Performance Testing" (Rev. 5)
- WO 99-20189/20196, "Replace Riley Module with a Calibrated Replacement"
- WO 99-12124, "Full PMI-0030 Service Air Cross-Tie Isolation Valve"

The inspectors identified no substantive concerns during observations of these work activities.

M1.2 Reference Leg Purge Panel 1H51P1432A Train Swap

a. Inspection Scope (62707)

The inspectors followed the guidance of IP 62707 and reviewed the tagouts and work orders for the swapping of purge trains on Test Reference Leg Purge Panel 1H51P1432A.

b. Observations and Findings

The purge train swap was classified by the licensee as an "infrequently performed evolution" (IPTE 99-005) and was thus carried out under the controls specified by PAP-1121, "Conduct of Infrequently Performed Tests or Evolutions." On December 11, 1999, the inspectors observed the pre-job brief conducted in the Unit 1 Control Room by the Task Manager. Personnel from the involved work groups attended and participated in the pre-job briefings. Termination criteria for the evolution as well as responsibilities of involved individuals were explicitly discussed. Actual swapping of the purge train is a local manipulation conducted inside the Containment Building. Subsequent to the pre-job brief, the inspector entered the Containment and observed the work activity as it was being executed by maintenance personnel per section 5.2.4 of procedure Instrument Maintenance Instruction IMI-E2-55, "Reference Leg Purge Panel 1H51-P1432A." The work was well-controlled and performed in accordance with plant procedures.

M1.3 Review of Surveillance Activities Associated with APRM Channel F Calibration

a. Inspection Scope (61726)

The inspectors followed the guidance of IP 61726 in reviewing portions of the work activities associated with the calibration of APRM Channel F.

b. Observations and Findings

The inspector observed portions of the December 7, 1999 performance of procedure SVI-C51-T0030F, "APRM F Channel Calibration for 1C51-K605F." During observation of the calibration activity, the inspector noted that for repetitive procedural steps associated with data gathering on individual LPRMs [local power range monitors), only one set of signoffs was provided in the body of the procedure. Upon further review, the inspector determined that this practice appeared to be allowed by Step 6.5.3.4 of procedure PAP-0517, "Preparation of Surveillance Instructions," Revision 1, which states:

> "A long or complex repetitive process should be used only when absolutely necessary. Then, one set of steps with one set of signoffs may be used. A step should be located at the end of the repetitive steps directing the performer to return to a previous step and repeat it, through a concluding step, until all items have been tested or the desired result achieved."

SVI-C51-T0030F requires repetitive performance of fifteen (15) steps for each of ten (10) LPRM detectors, providing for only one set of signoffs. The inspector questioned whether this practice was consistent with the licensee's human error reduction expectations. The inspector also questioned why this LPRM data gathering format was "absolutely necessary," a criterion suggested by PAP-0517 as the basis for usage of only one set of signoffs. In response to the inspector's questions, the licensee reviewed the history of performance of this procedure as well as other similarly formatted procedures, and concluded that, to date, human error has not been noted. The licensee indicated that a procedural clarification of the term "absolutely necessary" would be initiated to facilitate proper usage of the SVI formatting allowed by Step 6.5.3.4 of PAP 0517.

M1.4 Replacement of Control Rod Drive (CRD) System Stabilizing Valves

a. Inspection Scope (62707, 71707)

The inspectors reviewed the replacement and restoration to service of CRD system stabilizing valves that was performed on December 9, 1999 in accordance with work order 99-001387-000, "Stabilizing Valve Flow Incorrect," and OEO [operations evolution order] 99-1387, "Restoring C11 Stabilizing Valves to Service."

b Observations and Findings

Control rod drive stabilizing flow impacts control rod speed and, therefore, reactivity. Stabilizing valve assemblies contain a solenoid valve, strainer, and throttle valve.

During surveillance testing activities, the licensee determined that CRD stabilizing flow was degraded. The degradation was attributed to plugging of the stabilizing valve strainer. The licensee chose to replace the entire stabilizing valve assemblies to address the degraded flow condition.

The inspectors attended the pre-job briefing for this activity. The evolution steps were adequately reviewed. Operators and technicians were cautioned about the use of communication and peer checking techniques. Personnel were logged onto the appropriate radiation work permit and the applicable radiological controls were followed during the performance of the maintenance activity. The technicians were conservative during valve manipulations and while collecting potentially contaminated liquids that were vented. Proper peer checking and 3-part communications were used. System restoration and resetting of the assembly throttle valves was accomplished in accordance with work control documents. No deficiencies were identified with valve and system restoration.

The inspectors also observed that performance of this maintenance activity occurred at a location within containment that was below the suppression pool maximum surge level. Permanent step-off pads do not exist inside containment due to potential of plugging pump suction strainers located in the suppression pool during an event. During the performance of this task, technicians utilized yellow cotton bags and cloths on the floor grating to aid as step-off pads and to assist with foreign material controls. Additionally, the materials storage box from which the communications headsets were obtained for the maintenance activity, was open during the evolution and contained several ring binders of paper. The inspectors questioned the workers to determine if the square-footage of material from the binders and the cotton pads could impact ECCS system operability by plugging pump suction strainers located in the suppression pool in the unlikely event that an accident occurred during the maintenance activity. Both shift management and the technicians indicated that they knew of no limit on the square footage of transient material that was allowed to be inside containment during intermittent maintenance. Subsequently, the licensee initiated CR 99-3069 to request engineering assistance in determining the maximum amount of foreign material allowed inside containment.

M1.5 Conclusions on Conduct of Maintenance

Maintenance and surveillance activities observed were adequately planned and executed in the field without an adverse impact on plant operations. Pre-job briefings were thorough and activities were properly coordinated between departments and performed according to approved procedures.

M8 Miscellaneous Maintenance Issues (71707, 92700)

M8.1 (Closed) LER 50-440/1999-006: Disengaged Locking Spring on Relay Renders One Train of Standby Liquid Control (SLC) Inoperable. On November 24, 1999, the licensee discovered that an SLC system relay located in a control room cabinet had a disengaged locking spring. The purpose of the locking spring is to maintain the relay properly mounted in the cabinet during a seismic event. The licensee declared the SLC

Train "A" inoperable and entered the appropriate 7-day Limiting Condition for Operation per TS 3.1.7.A. The locking spring was promptly reinstalled and the SLC Train "A" was restored to operable. A walkdown of all control room panels was conducted and no other relays were in a similar condition. The licensee was unable to determine when the locking spring became disengaged; however, the appropriate actions were taken upon discovery of the condition. No violations were identified during the review of this event. This LER is closed.

III Engineering

E1 Conduct of Engineering

E1.1 Broken Bolts On Emergency Diesel Generator (EDG) Turbo Charger Tie Plate

a. Inspection Scope

On October 19, 1998, September 23, 1999, September 29, 1999, and November 24, 1999, the licensee identified loose or broken bolts on the Division II EDG turbo charger tie plate. Due to the safety significance of the EDG and the repetitive failures of this component the inspectors reviewed the operability determination for the EDG with multiple broken bolts on the turbo charger tie plate.

b. Observations and Findings

On November 24, 1999, the licensee identified that the Division II EDG, left bank turbo charger exhaust flange had two broken bolts associated with the flange and tie plate. The tie plate shares three bolts each with both the left bank and right bank exhaust flanges. The purpose of the bolts is to secure the exhaust flange to the casing and hold the tie plate down to provide rigidity between the left and right bank turbo chargers.

The inspectors could not ascertain from the documentation several aspects of operability including: the impact of two adjacent broken bolts on the ability of the exhaust flange to perform as designed, the seismic qualifications, and the effect of increased vibrations on continued operation. Because two bolts had sequentially broken, therefore demanding increased performance on the remaining bolt, and because of the repetitive nature of the failures, common mode failure of the bolts was of specific concern. The inspectors communicated these concerns to licensee personnel. The licensee had not evaluated if a common mode failure of the bolts occurred. This condition was re-evaluated under CR 99-3054. The subsequent operability determination (OD) indicated that the bolts and tie plates were for vibration dampening and did not perform a seismic function. The new OD also addressed the potential impact on the outlet flange with increased vibrations. The licensee restored the system during the Division II electrical outage that was performed during the week ending December 18, 1999. No further concerns were identified.

c. Conclusions

The licensee identified that repetitive failures of emergency diesel generator turbo charger bolts had occurred over the past year. However, this condition was not thoroughly evaluated in the initial operability determination. For example, the seismic qualification of the EDG, the effect of additional vibrations due to the loose/broken bolts, and the possibility for a common mode failure cause were not initially evaluated. It was determined during a subsequent evaluation that the diesel was seismically qualified, the purpose of the bolts was to assist in dampening vibrations, and that the EDG was operable because additional vibrations would not be of sufficient magnitude to impact continued diesel operation.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) Violation EA 96-367, 02014: Loss of Both Trains of Control Room Emergency Recirculation System Due to Emergency Closed Cooling Water Temperature Dropping Below 55 °F. This item was reviewed in Inspection Report 50-440/98002 and remained open pending NRC approval of a design change. The approval was granted via a license amendment on October 29, 1999. This item is now closed.

IV Plant Support

F8 Miscellaneous Fire protection Issues (92904)

F8.1 (Closed) IFI 50-440/98005-02: Housekeeping weaknesses in fire zone CC-1C. This item is closed based on it being entered into the licensee's corrective action program as PIF 98-0250.

F8.2 (Closed) IFI 50-440/98005-03: Development of a surveillance procedure that parallels the hydraulic design basis calculation for the fire protection water supply system. The inspectors reviewed PTI-P54-P0003, "Fire Main Flow Test," Revision 2 and its effective PICs No. 1 through 5. The licensee revised the procedure for the fire main loop No. 9 to simulate the major flow path for the highest safety related demand. In addition, the procedure required engineering analysis of the data taken to determine the coefficient of friction loss to ensure that the actual friction loss was within the assumed limits in the hydraulic calculation. The inspector considered the revised procedure to be acceptable for trending piping performance. This item is closed.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on January 5, 2000. The licensee acknowledged the findings presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

J. Wood, Vice President, Nuclear
H. Bergendahl, Director, Nuclear Services Department
B. Boles, Manager, Plant Engineering
N. Bonner, Director, Nuclear Maintenance Department
S. Davis, Superintendent, Plant Operations
G. Dunn, Manager, Regulatory Affairs
D. Gudger, Supervisor, Compliance
H. Hegrat, Manager, Quality Assurance
W. Kanda, General Manager, Nuclear Power Plant Department
T. Lentz, Manager, Design Engineering
B. Luthanen, Compliance Engineer
T. Rausch, Operations Manager
S. Sanford, Senior Compliance Engineer
R. Schrauder, Director, Nuclear Engineering Department
J. Sears, Manager, Radiation Protection
J. Sipp, Manager, Radwaste, Environmental, and Chemistry

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 61726:	Surveillance Observation
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71750:	Plant Support
IP 92700:	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92903:	Followup - Engineering
IP 92904:	Followup - Plant Support

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-440/99014-01	URI	disabled feedwater temperature compensation
50-440/99014-02	NCV	inadequate AEGTS tagout

Closed

50-440/98005-02	IFI	fire zone housekeeping concerns
50-440/98005-03	IFI	surveillance procedure for validating C factors
EA 96-367, 02014	VIO	ECC low temperature issue results in modification to temperature control valve
50-440/99014-02	NCV	inadequate AEGTS tagout

Discussed

None

LIST OF ACRONYMS USED

AEGTS	Annulus Exhaust Gas Treatment System
ATC	At-The-Controls
CFR	Code of Federal Regulations
CR	Condition Report
CRD	Control Rod Drive
DRP	Division of Reactor Projects
EA	Enforcement Action
ECC	Emergency Closed Cooling
EDG	Emergency Diesel Generators
IFI	Inspection Followup Item
IP	Inspection Procedure
IR	Inspection Report
LER	Licensee Event Report
MWt	Megawatts Thermal
NCV	Non-cited Violation
NRC	Nuclear Regulatory Commission
OD	Operability Determination
PAP	Plant Administrative Procedure
PIC	Procedure/Instruction Change
PIF	Potential Issue Form
RG	Regulatory Guide
RHR	Residual Heat Removal
SS	Shift Supervisor
SVI	Surveillance Instruction
TS	Technical Specification
URI	Unresolved Item
US	Unit Supervisor
VIO	Violation
WO	Work Order

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
801 WARRENVILLE ROAD
LISLE, ILLINOIS 60532-4351

March 09, 2000

Mr. John K. Wood
Vice President - Nuclear
FirstEnergy Nuclear Operating Company
P.O. Box 97, A200
Perry, OH 44081

SUBJECT: PERRY INSPECTION REPORT 50-440/99015(DRP)

Dear Mr. Wood:

On February 15, 2000, the NRC completed a routine safety inspection at the Perry Nuclear Power Plant. The enclosed report presents the results of that inspection.

During this inspection period, the overall conduct of activities at the Perry facility was conservative, with a continuing focus on safety. Routine surveillance and maintenance activities were conducted in accordance with required procedures. Operators effectively conducted several hundred control rod manipulations without error while attempting to identify the location of two minor fuel defects. However, a short duration flow mismatch between recirculation system loops occurred during a downpower evolution. While this was identified and corrected well within the time required by Technical Specifications, operators had an opportunity to recognize the mismatch earlier.

Based on the results of this inspection, the NRC has determined that one violation of NRC requirements occurred. This violation, which concerned the failure to meet surveillance test requirements for the Division 3, Unit 1 battery, is being treated as a Non-Cited Violation (NCV), consistent with Section VII.B.1.a of NRC's Enforcement Policy. The NCV is described in the inspection report. If you contest the violation or severity level of the NCV, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001, with copies to the Regional Administrator, Region III, and the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response, if you choose to provide one, will be placed in the NRC Public Document Room.

Sincerely,

Thomas J. Kozak, Chief
Reactor Projects Branch 4

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

Enclosure: Inspection Report 50-440/99015(DRP)

cc w/encl: B. Saunders, President - FENOC
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N. Bonner, Director, Nuclear Maintenance Department
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State Liaison Officer, State of Ohio
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U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-440
License No:	NPF-58
Report No:	50-440/99015(DRP)
Licensee:	FirstEnergy Nuclear Operating Company P.O. Box 97 A200 Perry, OH 44081
Facility:	Perry Nuclear Power Plant
Location:	Perry, OH
Dates:	January 6, 2000, through February 15, 2000
Inspectors:	C. Lipa, Senior Resident Inspector R. Vogt-Lowell, Resident Inspector
Approved by:	Thomas J. Kozak, Chief Reactor Projects Branch 4 Division of Reactor Projects

EXECUTIVE SUMMARY

Perry Nuclear Power Plant
NRC Inspection Report 50-440/99015(DRP)

This inspection report included resident inspectors' evaluations of aspects of licensee operations, engineering, maintenance, and plant support activities.

Operations

- Three Infrequently Performed Test/Evolutions were effectively conducted to locate and suppress two small fuel defects. Operations department personnel maintained a high level of reactivity control awareness during the several hundred control rod manipulations which occurred during the special evolutions. There was good coordination between the control room staff, reactor engineers, and in-field chemistry technicians in collecting and analyzing the samples. The inspectors also determined that control room operators demonstrated good attention to panel indications by identifying the fuel defects early (Section O1.1).

- During a downpower evolution, the licensed operator did not maintain the recirculation loop flows matched within the 5 percent limit specified in the Technical Specifications. A mismatch is allowed for up to 2 hours. Since the duration of the mismatch was only 10 minutes, no violation occurred. A stuck panel indicator contributed to the mismatch occurring. All operating crews were subsequently trained on the need to use redundant indications and verify the expected response when making changes to the plant (Section O1.2).

Maintenance

- Although plant material condition remained good, there were several equipment issues during the inspection period that challenged plant operators. Each of the items was corrected or scheduled for evaluation in the licensee's corrective action program (Section M2.1).

Engineering

- The inspectors determined that the licensee's initial operability determination for the Division 3 battery did not adequately support the assertion that the increased frequency battery performance discharge testing specified in Technical Specification was not required. Upon further review by the Office of Nuclear Reactor Regulation, it was determined that the surveillance testing requirements of the Technical Specifications were not met. This was a non-cited violation (Section E8.1).

Plant Support

- A personnel error by a radwaste operator resulted in the contamination of several portions of the radwaste building. This was not identified during shift turnover due to less than adequate panel walkdowns by the on-coming radwaste operator. A thorough investigation and appropriate management attention was directed to this issue (Section R1.1).

Report Details

Summary of Plant Status

The plant began this inspection period at 100 percent power. On January 8, the licensee implemented weekly power reductions to 90 percent to perform weekly control rod surveillance testing. The downpowers were recommended based on early indications of a small fuel defect, which had been detected through the identification of a slight increase in offgas pre-treatment activity. Plant power was reduced to 65 percent on January 13, 2000, for fuel defect localization testing to determine the location of the defect. The defect location was identified and the flux was suppressed by inserting one control rod (54-31) on January 16, 2000. The plant was subsequently returned to full power on January 16, 2000. In order to maintain the defect suppression, plant management directed that part of the weekly control rod surveillance testing activities would be conducted at 90 percent power instead of 100 percent. This restriction continued throughout the remainder of the inspection period, and was expected to remain in effect until the next refueling outage (February 2001).

On January 31, plant operators identified an increase in the offgas post-treatment radiation monitor which indicated that the fuel defect had degraded or that a second small fuel defect was present. On February 5, power was reduced to 65 percent to test whether the defect that was suppressed on January 16 remained adequately suppressed. The licensee determined that the first defect remained adequately suppressed and returned the reactor to full power on February 6. A full core fuel defect localization test was conducted at approximately 65 percent power from February 11 through February 14 to locate the second defect. The location of the second defect was identified and a second control rod (42-51) was inserted to suppress the defect. Power was restored to full power on February 15, 2000.

I. Operations

O1 Conduct of Operations

O1.1 Fuel Defect Testing and Suppression Infrequently Performed Test/Evolutions (IPTE)

a. Inspection Scope (71707)

The inspectors followed the guidance of Inspection Procedure (IP) 71707 in assessing operator performance in isolating and suppressing two small fuel defects which were detected through the identification of a slight increasing trend in the off-gas radiation monitors.

b. Observations and Findings

Operations, reactor engineering, and chemistry department personnel developed a special evolution to localize and suppress a fuel defect that was detected on December 29, 1999. On January 13, 2000, the evolution was commenced. This evolution was classified as an IPTE, which resulted in increased management oversight. The inspectors observed the briefings associated with this evolution and determined that

the briefings were formal and had an appropriate focus on human performance and plant safety. The evolution involved a large number of repetitive control rod manipulations, with subsequent chemistry samples, to identify the specific location of the defect. The test was conducted throughout the weekend. In all, operations department personnel performed several hundred control rod manipulations without error. The operators maintained their sensitivity for reactivity controls throughout the evolution. In addition, operators used appropriate three-way communications amongst themselves and with other personnel. After data review and consultation with General Electric, the licensee determined that a small defect existed and this defect was suppressed by inserting control rod 54-31. Subsequent samples showed that the defect appeared to be adequately suppressed.

On January 31, 2000, plant operators identified an increase in the offgas post-treatment radiation monitor which indicated that the fuel defect had degraded or that a second small fuel defect was present. On February 5, power was reduced to 65 percent to perform testing. The licensee performed a reduced scope fuel defect localization test and moved only those control rods in close proximity to the fully inserted rod. The purpose of the test was to obtain additional data to determine whether the first fuel defect remained adequately suppressed. Based on the results of the testing, the licensee determined that the first defect remained adequately suppressed and returned the plant to full power on February 6. This evolution was classified as an IPTE and was effectively implemented.

On February 11, 2000, a full core fuel defect localization test was conducted at approximately 65 percent power to identify the location of the second defect. The location of the second defect was identified on February 14, 2000, and control rod 42-51 was fully inserted to suppress the defect. The reactor was restored to full power on February 15, 2000. This evolution was also performed with the additional management oversight of an IPTE. The inspectors determined that the evolution was well coordinated and performed.

c. Conclusions

The inspectors concluded that Infrequently Performed Test/Evolutions were effectively conducted to locate and suppress two small fuel defects. Operations department personnel maintained a high level of reactivity control awareness during the several hundred control rod manipulations which occurred during the special evolutions. There was good coordination between the control room staff, reactor engineers, and in-field chemistry technicians in collecting and analyzing the samples. The inspectors also determined that control room operators demonstrated good attention to panel indications by identifying the fuel defects early.

O1.2 Reactor Recirculation Loop Flow Mismatch Exceeded Technical Specification (TS) Limits During Downpower Evolution

a. Inspection Scope (71707)

While control room licensed operators reduced reactor power on February 11, 2000, the inspectors and licensee personnel observed that the "A" and "B" recirculation system loop flows did not appear to be matched as required by TS. The inspectors followed the guidance in IP 71707 to review this issue.

b. Observations and Findings

During a downpower evolution on February 11, 2000, licensed operators in the control room identified that the "A" and "B" recirculation loop system flows were not matched. As the operator reduced recirculation flow, the needle on one of the flow meters stuck, which misled the operator as he attempted to maintain equal flow through each loop. Within a short period of time, this operator and the Shift Supervisor began to discuss the flows and compare redundant indications. Once the operators discovered the stuck meter, the operator took prompt action to match the "A" and "B" loop flows. During a subsequent review of computer traces, the Shift Technical Advisor identified that the actual mismatch of 8 percent exceeded the 5 percent allowed by TS 3.4.1 for approximately 10 minutes. Technical Specification 3.4.1.A allows the mismatch to exist for up to 2 hours before action must be taken to shut down one recirculation pump. Since the duration of the excessive mismatch was only 10 minutes, there was no violation of TS. The licensee initiated condition report 00.431 and promptly prepared a lessons learned sheet. Training sessions were held for each crew as they came on shift to ensure timely awareness of the lessons learned from this issue. The main emphasis of the training sessions was on the importance of using redundant indications and verifying the expected response when making changes to the plant. The inspectors reviewed the traces for the previous downpower on February 5, 2000, and noted that the loop flows were properly maintained well within the 5 percent limit.

c. Conclusions

During a downpower evolution, the licensed operator did not maintain the recirculation loop flows matched within the 5 percent limit specified in the TSs. A mismatch is allowed for up to 2 hours. Since the duration of the mismatch was only 10 minutes, no violation occurred. A stuck panel indicator contributed to the mismatch occurring. All operating crews were subsequently trained on the need to use redundant indications and verify the expected response when making changes to the plant.

O2 Operational Status of Facilities and Equipment

O2.1 General Plant Tours and System Walkdowns (71707)

The inspectors followed the guidance of IP 71707 in walking down accessible portions of several systems and areas, including:

- Emergency core cooling system pump rooms
- Safety-related electrical switchgear rooms
- Residual heat removal (RHR) heat exchanger rooms
- Fuel handling building
- Safety-related battery rooms
- Reactor core isolation cooling (RCIC) system
- Emergency diesel generators (EDG)

Equipment operability, material condition, and housekeeping were acceptable in all cases. Several minor discrepancies were brought to the licensee's attention and were corrected. The inspectors identified no substantive concerns as a result of these walkdowns.

O8 Miscellaneous Operations Issues (92700)

O8.1 (Closed) LER 50-440/1999-004-00: Loss of Safety Function Results in TS 3.0.3 Entry. On September 16, 1999, Perry Plant personnel observed a funnel-shaped cloud near the plant. In accordance with plant procedures, operators breached the control room boundary as one of the specified compensatory measures. This action had been determined to be necessary to prevent a tornado-generated depressurization event from failing architectural walls, which could potentially affect safety-related equipment. When the control room boundary was breached, this disabled both trains of control room emergency recirculation and resulted in a TS 3.0.3 entry.

Plant modifications were planned to reduce reliance on compensatory measures by the Spring 2001 refueling outage. The initial identification of the plant's potential vulnerability to a design basis tornado had been reported in LER 1999-001, which remains open. Corrective actions taken in response to the TS 3.0.3 entry on September 16, 1999, included revising procedures to protect the control complex without disabling the control room recirculation system upon identification of a tornado warning or sighting. The inspectors verified that corrective actions were in place. This LER is closed.

O8.2 (Closed) LER 50-440/1999-005-00: Control Rod Moved Without Re-establishing a More Restrictive Rod Withdrawal Limit During Testing. On November 4, 1999, the licensee reported this event as a condition prohibited by TS, based on the movement of control rods with the rod withdrawal limiter (RWL) being inoperable. After further investigation and consultation with General Electric personnel, it was determined that the RWL remained operable at that time. The event was retracted on November 30, 1999. The licensee acknowledged that the event did result in a procedure violation and this was dispositioned in Inspection Report 50-440/99011 as a minor violation. The licensees's corrective actions included: (1) revising applicable procedures to clarify operation of the

RWL, (2) reviewing this operator error to discuss lessons learned in requalification training, and, (3) clarifying the responsibility of the Independent Verifier for movement of control rods. This LER is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Review of Routine Maintenance and Surveillance Activities (62707, 61726)

The inspectors observed or reviewed all or portions of the following work activities:

- SVI-B21-T0368, "Safety Relief Valve Tail Pipe Pressure Switch"
- SVI-R43-T1317, "Diesel Generator Start and Load Division 1"
- SVI-E22-T0195-G, "HPCS Suppression Pool High Level Channel G Functional for 1E22-N655G"
- SVI-C11-T1003B, "Control Rod Exercise (Part 2)"
- SVI-M15-T3015, "Annulus Exhaust Gas Treatment Charcoal Adsorber Operability Test"

The inspectors identified no concerns during observations of these activities.

M2 Maintenance and Materiel Condition of Facilities and Equipment

M2.1 Challenges to Plant Operators

a. Inspection Scope (62707, 71707, 37551)

The inspectors reviewed recent equipment issues and emergent work items to ensure appropriate operability evaluations were performed, TS requirements were met, repairs were made, and root causes were identified where appropriate. The inspectors also reviewed the Updated Safety Analysis Report (USAR) and system operating procedures.

b. Observations and Findings

The inspectors noted that although plant material condition remained good, there were several equipment issues and emergent work items during the inspection period that challenged plant operators. The examples are listed below:

- The safety-related ventilation system for switch gear and battery rooms was routinely operated in the recirculation mode vice the normal mode. When questioned, engineering and operations department personnel informed the

inspectors that this has been occurring each winter for several years. In the normal mode, the temperatures in certain areas, such as the Unit 2 Division 3 battery room, were lower than desired. In the recirculation mode, minimum temperatures were met and safety-related equipment operability was maintained. The licensee acknowledged that the need to operate in recirculation was compensating for a design weakness. The system was originally designed for two operating Units and there was not enough heat load to maintain minimum temperatures in the winter with only one operating Unit. Plans to correct this condition were underway in coordination with the redesign of the new entrance to the radiation control area. The inspectors reviewed the USAR and system operating instructions and determined that routine operation in the recirculation mode was not prohibited. Control room operators considered the need to operate the system in this mode to be a minor burden because operators only needed to place the system in the recirculation mode once at the beginning of each winter.

- During EDG surveillance tests in the winter months, the licensee routinely needed to start the emergency closed cooling (ECC) system to increase indicated temperature in that system. Also, during some EDG surveillance tests, plant operators started room coolers for RCIC and RHR pump rooms to increase temperatures in the ECC system. Based on discussions with control room personnel, operation of the ECC system during EDG surveillances was necessary in the winter months to maintain ECC system operability. The emergency service water system that was operated to support the EDG surveillance provided cool water to the ECC system heat exchanger. This resulted in reduced temperatures in the ECC system because the ECC system was normally in standby with no heat loads. In order to maintain the ECC system operable, the temperature was required to be greater that 55 degrees Fahrenheit. Engineering department management acknowledged that modifications were planned to improve the ability of the ECC system to be maintained above 55 degrees F while in standby. The ability of the system to respond properly in a postulated accident was not in question. Operations department management did not consider the additional operation of the ECC system to be an excessive burden, but did acknowledge that it was a challenge. The most recent System Quarterly Assessment Report by engineering department personnel stated that the ECC system was on the list of "Systems Declining and Needing Improvement." The report stated that the system shows a decline due to the increased system run frequency. The system must be started approximately daily to equalize bulk system temperature due to the heat exchanger temperature element locations.

- Recent self-revealing problems with the leak detection system resulted in challenges to operators. Several Riley temperature modules for main steam isolation valve (MSIV) logic failed, resulting in ½ MSIV isolations and alarms in the control room. Through an expanded investigation, engineering and maintenance department personnel determined the cause to be related to diodes within the module and planned repairs. Also, the reactor water cleanup valve

room differential temperature element reading was typically near or at the alarm set point of 23 degrees F differential. The licensee was investigating the need for a set point change or a potential problem with airflow through the room.

- Control room operators identified a trend in the need to more frequently operate the drywell pressure vent system due to a slow increase in drywell pressure over several days. The inspectors noted in the operator logs that the vent system was operated approximately every 4 or 5 days. System engineering personnel suspected the cause to be a leak from the air system and worked with operations to develop a plan to isolate certain nonsafety-related air valves within the drywell. By the end of the inspection period, the need to vent had slowed to only about once per 10 days. Additional actions were planned as part of CR 99-2868.

- The rod control and information system (RC&IS) experienced numerous lockups in the months of December 1999 and January 2000. Engineering and maintenance personnel began extensive trouble-shooting and requested the General Electric system expert's assistance on site. Several of the lock-ups would not reset right away, requiring Operations personnel to enter ONI-C11-1, "Inability to Move Control Rods." The ability to scram the control rods was maintained, but individual rods could not be moved with the RC&IS system locked up. Operations department personnel removed the doors from the control room cabinets to improve ventilation. This temporarily resolved some of the lockups. Several circuit cards and transponder cards were replaced and a jumper was placed around a loose wire with a temporary modification (TM) on February 2, 2000. The system had no additional lockups throughout the inspection period following the TM installation. The panel doors were restored and the challenges from this system have diminished.

- During the inspection period, there were several problems with the containment air locks. This did not cause any safety concerns, but did impact ease of entry into the containment for scheduled work and routine plant rounds. Maintenance was expedited to restore the air locks and two CRs (00-0411 and 00-0418) were written to address the issues.

The inspectors discussed the issues with Operations and Engineering department management. Although the licensee agreed that these items were challenges, none of the items met the licensee's definition for Operator Work Arounds. The inspector noted that each of the items was being evaluated or corrected within the licensee's corrective action program.

c. Conclusions

Although plant material condition remained good, there were several equipment issues during the inspection period that challenged plant operators. Each of the items was corrected or scheduled for evaluation in the licensee's corrective action program.

M8 Miscellaneous Maintenance Issues

M8.1 (Closed) Violation 50-440/94006-06a: Failure to take adequate corrective actions to refurbish circuit breakers. This violation is in the licensee's corrective action program as CR 94-306. Part b of the violation was reviewed and closed in Inspection Report 50-440/96016. This item is closed.

III. Engineering

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) Unresolved Item (URI) 50-440/99001-04: Increased Frequency Battery Performance Testing Not Implemented According to TS

a. Inspection Scope (92903)

The inspectors followed the guidance of IP 92903 in reviewing the URI. The inspectors reviewed the licensee's completed investigation for CR 99-0364 and the associated surveillance tests. The inspectors also reviewed a response to Technical Interface Agreement (TIA) 99-006, Revision 1, from the Office of Nuclear Reactor Regulation (NRR), dated October 29, 1999, which is included as Attachment 1 to this inspection report.

b. Observations and Findings

On February 17, 1999, the licensee identified that the date (1983) which had been used to determine when the Division 3 batteries were initially placed into service was not the correct date to use for tracking battery service life. Actually, the batteries were in storage on a trickle charge from 1978 until 1983, which added 5 years to the service life. The battery vendor specified that the expected battery service life was 20 years. Technical Specifications required testing at an increased frequency (every 18 months) once the battery reached 85 percent of service life, which was in 1995. The most recent performance tests were October 7, 1996, for the Unit 1 battery and July 29, 1996, for the Unit 2 (backup) battery. The licensee performed an Operability Determination (OD) and determined that the Unit 1 battery remained operable. This was based on the actual test results and that many of the individual cells in the Unit 1 battery had been replaced over time. The Unit 2 battery was declared inoperable since all cells in this battery were more than 20 years old. The inspectors requested assistance from NRR in reviewing this issue. In the response to TIA 99-006, Revision 1, NRR provided their evaluation of: (1) the licensee's initial OD, (2) the licensee's subsequent OD, and (3) whether the increased frequency testing requirements of TS SR 3.8.4.8 applied to the Division 3 batteries. A summary is provided below:

(1) The licensee's initial OD stated, "The Unit 1 Division 3 battery has an average physical age of 9.7 years," and "based upon battery performance and numerous cell replacements, this battery is at the mid-point of its service life." NRR's evaluation of this OD, as discussed in the TIA, was that it is not industry practice

and it is not acceptable to calculate the age of the battery using the arithmetic average of individual cells. The licensee's statements were not backed up with any documentation or reference to technical literature discussing such calculations for establishing the battery age. C&D Technologies, manufacturer of the battery, confirmed that the overall battery performance will not degrade in the near future; however, the Unit 1 Division 3 battery performance tests showed that the battery is on what is called "the knee" of the capacity vs. life curve, and the drop in capacity from 106 percent in 1996 to 98.9 percent in 1999, 7 percent in 3 years, shows a rapid degradation, and the method of calculation used by the licensee does not reflect the true life expectancy of the battery.

(2) The licensee's revised OD addressed the life of the installed battery using comparison to a typical battery capacity versus percent battery life curve. In the response to the TIA, NRR addressed the use of this method as follows: The "typical" battery curves for batteries are published in promotional and marketing literature and academic engineering books. Manufacturer technical data does not contain such curves but will issue a warranty stating that the lead antimony and lead calcium stationary batteries used in float service will furnish at least 80 percent of their rated capacity for 20 years after date of shipment. The age for a composite battery is the age of the oldest cells, because the cells are in series, and the oldest cells are expected to fail between 85 to 100 percent of the expected life of 20 years. The licensee used typical battery capacity versus percent battery life for determining the life of the installed battery. The battery curve (capacity vs. battery life) is not used to determine the age of a battery; therefore, it is not acceptable for a composite battery installed at Perry.

(3) The NRR staff disagreed with the licensee's method of determining an overall effective age of the Unit 1 Division 3 composite battery. As discussed in the response to the TIA, nine cells of the Unit 1 Division 3 batteries were the original cells, which were installed on January 11, 1978. These cells should be used for determining the age of the battery, which is over 20 years old. Therefore, the staff concludes that surveillance requirement SR 3.8.4.8 should have been performed at the 18-month frequency. The licensee promptly tested both the Unit 1 and 2 Division 3 batteries once the age of the batteries came into question and the batteries successfully passed the performance discharge tests.

Technical Specification Surveillance Requirement (SR) 3.8.4.8 requires that a performance discharge test be completed every 18 months once the Division 3 battery shows degradation or has reached 85 percent of expected life. Licensee documentation indicated that Division 3 battery surveillance tests were being tracked using an expected battery life of 20 years. The SR was required to be performed at the increased frequency since January 11, 1995, when nine of the cells became 17 years old (85 percent of expected life). Since the last performance discharge test on the Unit 1 battery was October 7, 1996, the SR was required to be met by August 22, 1998. The failure to perform the surveillance at the increased frequency between August 22, 1998, and February 28, 1999, is a violation of TS SR 3.8.4.8. This Severity Level IV violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy. **(NCV 50-440/99015-01(DRP))**

The licensee's corrective actions included: (1) promptly performing the surveillance tests once the age of the batteries was identified, (2) scheduling subsequent surveillance tests at the correct frequency, (3) evaluating the need to replace the batteries, and (4) sharing the information with the industry as an Operating Experience Report.

c. Conclusions

The inspectors determined that the licensee's initial operability determination did not adequately support the assertion that the increased frequency battery performance discharge testing specified in TS was not required. Upon further review by the Office of Nuclear Reactor Regulation, it was determined that the surveillance testing requirements of the TS were not met. This was a non-cited violation.

E8.2 (Closed) URI 50-440/99008-01: Repeat Problems with Division 3 EDG Testable Rupture Disc (TRD). The TRD lift force was increasing between test intervals and was found to exceed the licensee's allowable value on June 8, 1999. The interim disposition of this issue was to leave the disc in the open position pending further engineering review per CR 99-1569. In response to CR 99-1569, the licensee consulted industry experts and performed additional calculations. This review determined that although the lift force was higher than desired, the TRD would have lifted without causing excessively high back pressure on EDG turbocharger exhaust. Therefore, the EDG remained operable at the higher lift force. The licensee planned additional corrective actions to modify the diesel exhaust for all 3 EDGs to replace the TRD with a rupture disc. This item is closed.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 Personnel Error Results in Radwaste Tank Overflow

a. Inspection Scope (71750)

The inspectors reviewed the licensee's investigation for CR 00-0066. This issue involved a radwaste tank that overflowed and contaminated several areas of the radwaste building. The inspectors walked down the radwaste control room panels and held discussions with radwaste department personnel.

b. Observations and Findings

On January 7, 2000, a radwaste technician made an error while changing valve positions in the radwaste system. Approximately 12 hours later, this resulted in the equipment drain separator tank overflowing and contaminating portions of two floors in the radwaste building and a portion of the radwaste control room. Upon identification, the proper valve lineup was established and CR 00-0066 was initiated to review the

circumstances surrounding this issue. The management team also determined that the "event-free clock" should be reset as a result of this issue.

The valve misalignment occurred at approximately 2:35 a.m. and was identified by maintenance personnel at approximately 3:15 p.m. when they spotted a large puddle in the radwaste building. Through the investigation, the licensee identified that there were other opportunities to identify the error prior to 3:15 p.m. The first instance was when the radwaste operator noted that one valve was in the wrong position approximately 2 hours later. He repositioned that valve, but did not review any other valve positions at that time. A second opportunity to identify the error was when the shift change occurred between night shift and day shift radwaste operators. During the shift change, the on-coming operator walked down the panels, but failed to identify the valve out of position. The licensee's corrective actions focused on improving the written policies and expectations for radwaste operators to improve work practices in the radwaste control room. Bench marking with the main control room was planned to compare expectations for self-checking, configuration control, and panel walkdowns.

c. Conclusions

A personnel error by a radwaste operator resulted in the contamination of several portions of the radwaste building. This was not identified during shift turnover due to less than adequate panel walkdowns by the on-coming radwaste operator. A thorough investigation and appropriate management attention was directed to this issue.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on February 15, 2000. The licensee acknowledged the findings presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

X3 Management Meeting Summary

On February 1, 2000, the NRC Region III Administrator and other staff members conducted a public meeting with several licensee management individuals in the Region III Office. Topics discussed included the licensee's corrective action program and management focus areas. The handout from this meeting is included as Attachment 2 to this inspection report.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

J. Wood, Vice President, Nuclear
H. Bergendahl, Director, Nuclear Services Department
B. Boles, Manager, Plant Engineering
N. Bonner, Director, Nuclear Maintenance Department
S. Davis, Superintendent, Plant Operations
G. Dunn, Manager, Regulatory Affairs
D. Gudger, Supervisor, Compliance
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R. Schrauder, Director, Nuclear Engineering Department
J. Sears, Manager, Radiation Protection
J. Sipp, Manager, Radwaste, Environmental, and Chemistry

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 61726:	Surveillance Observation
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71750:	Plant Support
IP 92700:	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92903:	Followup - Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-440/99015-01	NCV	Failure to Test Division 3 Batteries at Increased Frequency

Closed

50-440/94006-06a	VIO	Failure to Take Adequate Corrective Actions to Refurbish Circuit Breakers
50-440/99001-04	URI	Increased Frequency Battery Performance Testing Not Implemented According to TS
50-440/99004-00	LER	Loss of Control Room Recirculation Safety Function Results in TS 3.0.3 Entry
50-440/99005-00	LER	Control Rod Moved Without Re-establishing a More Restrictive Rod Withdrawal Limit During Testing
50-440/99008-01	URI	Repeat Problems with Division 3 EDG Testable Rupture Disc
50-440/99015-01	NCV	Failure to Test Division 3 Batteries at Increased Frequency

Discussed

None

LIST OF ACRONYMS USED

CFR	Code of Federal Regulations
CR	Condition Report
DRP	Division of Reactor Projects
ECC	Emergency Closed Cooling
EDG	Emergency Diesel Generators
HPCS	High Pressure Core Spray
IP	Inspection Procedure
IPTE	Infrequently Performed Test/Evolution
IR	Inspection Report
LER	Licensee Event Report
MSIV	Main Steam Isolation Valve
NCV	Non-cited Violation
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
OD	Operability Determination
ONI	Off-Normal Instruction
RCIC	Reactor Core Isolation Cooling
RC&IS	Rod Control and Information System
RHR	Residual Heat Removal
RWL	Rod Withdrawal Limiter
SE	Safety Evaluation
SOI	System Operating Instruction
SR	Surveillance Requirements
SVI	Surveillance Instruction
TM	Temporary Modification
TRD	Testable Rupture Disc
TS	Technical Specification
URI	Unresolved Item
US	Unit Supervisor
USAR	Updated Safety Analysis Report
VIO	Violation
WO	Work Order

Attachments:
1. Task Interface Agreement (TIA) 99-006, Revision 1, from the Office of Nuclear Reactor Regulation (NRR), dated October 29, 1999.
2. Handouts from a public management meeting conducted on February 1, 2000.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

October 29, 1999

MEMORANDUM TO: Geoffrey G. Grant, Director
Division of Reactor Projects
Region III

FROM: Suzanne C. Black, Deputy Director
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

SUBJECT: PERRY BATTERY AGING AND TECHNICAL SPECIFICATION COMPLIANCE CONCERN -TIA NO. 99-006, REVISION 1

Region III Task Interface Agreement 99-006, Revision 1, dated June 2, 1999, requested that NRR review several questions related to the determination of battery age and technical specification compliance. Perry Nuclear Power Plant Technical Specification Surveillance Requirement (SR) 3.8.4.8 requires that a performance discharge test be performed on 125 VDC batteries and chargers every 60 months and that the frequency of testing be increased to every 18 months when either the batteries show degradation or when they reach 85% of their service life. Degradation is indicated, according to IEEE Standard 450-1980, "IEEE Recommended Practice for Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Generating Stations and Substations", when the battery capacity drops more than 10% of rated capacity from its average on previous performance tests or is below 90% of the manufacturer's rating. Battery service life, which is not defined in either IEEE-450 or the Perry Technical Specifications, is generally accepted to be 20 years. Therefore, SR 3.8.4.8 should be performed on an 18-month frequency when the battery becomes 17 years old (i.e., 85% of the expected service life).

Perry has two fully redundant 125 VDC safety-related batteries and battery chargers (Unit 1 and Unit 2) that are used for Division 3 loads (i.e., the high pressure core spray system (HPCS)). During plant construction, the original Division 3 batteries were placed on a float charge in warehouse storage on January 11, 1978. The batteries were installed in the plant in late 1983. Preoperational testing for the Unit 1 batteries was performed in November 1984 and the same testing was performed on the Unit 2 batteries in October 1987. While Perry Unit 2 was eventually canceled, selected systems, including the Unit 2 Division 3 batteries, have been maintained operable and have periodically supported Unit 1 systems.

Questions have been raised regarding the licensee's practice of replacing individual battery cells and how to determine battery age with respect to performing SR 3.8.4.8. Each battery contains 60 cells (20 jars). Over the past 21 years, 51 of the 60 battery cells for the Unit 1 battery have been replaced while 9 cells have been in service beyond the expected service life of 20 years. Almost all of the battery cells for the Unit 2 battery are the original cells and are over 20 years old.

Attachment 1

On February 1, 1999, NRC inspectors observed physical signs of aging on both the Unit 1 and Unit 2 batteries and questioned the operability of the batteries. In responding to these concerns, the licensee subsequently determined that the battery age was assumed to be the preoperational testing date (i.e., 1984) in lieu of the initial storage date. Although IEEE-450 is silent with regard to battery service life and time spent while in storage, the licensee conservatively assumed that service life began when the batteries were first placed on the float charge thus making the batteries 5 years older than previously accepted.

On February 17, 1999, the licensee declared the Unit 2 Division 3 batteries inoperable based upon the age of the battery cells exceeding the expected service life of 20 years compounded by not having performed a performance discharge test within the last 18 months. With regard to the Unit 1 battery, the licensee calculated an effective age of 9.7 years based on an arithmetic average of all 60 cells. Based on this information, the licensee concluded that the normal 60-month frequency for SR 3.8.4.8 was appropriate. In addition, the licensee compared a recently performed discharge test of the Unit 1 battery to a typical battery curve and concluded that the battery was at 78 percent of its service life. The licensee used this latter piece of information to further bolster its argument that a 60-month frequency is appropriate for SR 3.8.4.8. The licensee, on its own initiative, subsequently performed successful performance discharge tests on both the Unit 1 and Unit 2 Division 3 batteries.

On February 18, 1999, the RCIC system was secured and declared inoperable. In accordance with the Perry Technical Specifications, the RCIC system may be inoperable for up to 14 days provided that HPCS remains operable. If both RCIC and HPCS are inoperable, the plant must enter Mode 3 within 12 hours. Due to the licensee's determination that both the Unit 1 Division 3 batteries and the HPCS system remained operable, a plant shutdown was avoided.

The TIA focuses on determining the age of a composite battery and how to interpret SR 3.8.4.8. The TIA also questions whether appropriate actions were taken by the licensee when the RCIC system was declared inoperable during the time when operability of the HPCS system was in question. Finally, the TIA questions the significance of low individual cell voltage on the overall acceptance of battery performance.

We have reviewed these issues and conclude that they have been resolved as described below.

1. **Is it acceptable to calculate an effective age of a battery using an arithmetic average of the individual cell age in a particular battery?**

   It is not industry practice and it is not acceptable to calculate the age of the battery using the arithmetic average. Licensee Document #2, "Assessment Form," states: "The Unit 1 Division 3 battery (IEEE-S0005) has an average physical age of 9.7 years," and Document #4, "Operability Determination," states: "Based upon battery performance and numerous cell replacements, this battery is at mid-point service life." These statements are not backed up with any documentation or reference to technical literature discussing such calculations for establishing the battery age. C&D Technologies, manufacturer of

the battery, confirmed that the overall battery performance will not degrade in the near future; however, the Unit 1 Division 3 battery performance tests showed that the battery is on what is called "the knee" of the capacity vs. life curve, and the drop in capacity from 106% in 1996 to 98.9% in 1999, 7% in three years, shows a rapid degradation, and the method of calculation used by the licensee does not reflect the true life expectancy of the battery.

2. **Is it acceptable to use a typical battery curve to determine an approximate age for a composite battery?**

   The "typical" battery curves for batteries are published in promotional and marketing literature and academic engineering books. Manufacturer technical data does not contain such curves but will issue a warranty stating that the lead antimony and lead calcium stationary batteries used in float service will furnish at least 80% of their rated capacity for 20 years after date of shipment. The age for a composite battery is the age of the oldest cell(s) because the cell(s) is (are) in series and the oldest cell(s) is (are) expected to fail between 85 to 100% of its expected life of 20 years.

   The licensee used typical battery capacity versus percent battery life for determining the life of the installed battery. The battery curve (capacity vs. battery life) is not used to determine the age of a battery; therefore, it is not acceptable for a composite battery installed at Perry.

3. **Based on the answers to Questions 1 and 2, did the increased frequency testing requirements of TS SR 3.8.4.8 apply to the Unit 1 Division 3 battery in this case?**

   As described in response to Question 1 above, the staff disagrees with the licensee's method of determining an overall effective age of the Unit 1 composite battery. Cells 10, 11, 12, 31, 32, 33, 40, 41, and 42 of the Unit 1 Division 3 batteries are the original cells and were installed on January 11, 1978. These cells should be used for determining the age of the battery, which is over 20 years old. Therefore, the staff concludes that surveillance requirement SR 3.8.4.8 should have been performed at the 18-month frequency.

4. **If so, does NRR agree that the licensee should have either commenced a plant shutdown or pursued a Notice of Enforcement Discretion on February 19, 1999, due to concurrent inoperability of the RCIC system and both Division 3 batteries?**

   It is not apparent that both of the Division 3 batteries were inoperable as maintained in the above question. Both the Unit 1 and 2 Division 3 batteries successfully passed the performance discharge test once the age of the batteries came into question. Therefore, the staff concludes that the batteries would have performed their intended safety function and that there is no safety issue associated with the TIA.

However, in a regulatory sense, the staff concludes that the licensee was non-conservative in its decision making. In accordance with NRC Inspection Manual Part 9900, "Operable/Operability: Ensuring the Functional Capability of a System or Component," licensees are required to make a prompt operability determination whenever a system, structure, or component does not conform to all aspects of the current licensing basis, including codes and standards, design criteria, and commitments. According to the definition of operability, a safety or safety support system or structure must be capable of performing its specified function(s) of prevention or mitigation as described in the current licensing basis, particularly the technical specification bases or USAR. In this situation, the licensee made a prompt operability determination and concluded that the 60-month frequency for SR 3.8.4.8 was appropriate and that the batteries remained operable. The licensee made this determination based upon recent test history which indicated that performance of the nine original cells in question was not significantly different than that of any other cells within the battery and discussions with the battery manufacturer (C&D Technologies Corporate Engineering) who confirmed that the cells in question are not now detrimentally affecting overall battery performance nor are they likely to degrade battery performance in the near future.

As stated in response to Questions 1 and 2 above, the staff disagrees with the licensee's methods of determining the age of the Unit 1 Division 3 batteries. Rather than declaring the Unit 1 Division 3 batteries inoperable, the staff believes that a more appropriate action would have been to enter SR 3.0.3 for a missed surveillance. SR 3.0.3 provides for an additional 24 hours to perform a missed surveillance before declaring that the LCO has not been met and entering the appropriate Condition (in this case, declaring the Division 3 batteries and, in turn, HPCS inoperable). Since the performance discharge test requires approximately one week to perform and the technical specifications do not address extensions of SR 3.0.3, it would appear logical that a request for enforcement discretion would have been appropriate. The staff believes that the period of enforcement discretion would have encompassed the duration when the RCIC system was inoperable.

5. What effect does low individual cell voltage have on overall acceptance of battery performance, and is there a minimum allowable value?

The individual cell voltage is based on the plate alloy, the specific gravity of the electrolyte, and the temperature of the cell. The battery manufacturers publish tables recommending the minimum float voltage per cell (vpc) and nominal float vpc range for specific gravities values. IEEE 450, "Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications" (1980, 1987, and 1995), advises that "prolonged operation of cells below 2.13v can reduce the life expectancy of cells" and "a cell voltage of 2.07v or below under float conditions indicates internal cell problems and therefore may affect the performance of the battery."

The list of documents submitted and reviewed by NRR's Electrical & Instrumentation & Controls Branch (EEIB) is attached.

Attachment: References

cc: A. Blough, RI
L. Plisco, RII
K. Brockman, RIV

DOCUMENTS SUBMITTED AND REVIEWED BY EEIB

1. Condition Report No. 99-0364 — February 17, 1999

2. Assessment Form No. 99-0364 — February 22, 1999

3. Memorandum from W. J. Colvin to K. D. Brandt (The Illuminating Company), "Maintenance Rule Applicable Review" — February 19, 1999

4. Operability Determination No. 99-0364 (Unit 1 Division 3 Battery) — February 18, 1999

5. Operability Determination No. 99-0364 (Unit 2 Division 3 Battery) — February 18, 1999

6. Memorandum from V. Terrasi, Perry Nuclear Power Plant, to PIF Investigator, "Maintenance Rule Applicability" — February 25, 1999

7. Cause Analysis No. 99-30364 — March 19, 1999

8. Corrective Action No. 99-0364 — March 13, 1999

9. Condition Report No. 99-0364 — March 9, 1999

10. Assessment Form No. 99-0305 — March 4, 1999

11. Equipment Storage Maintenance Requirements — February 23, 1978

12. List 1E22S005, Attachment 5 to CR99-0364 (History of Cell Replacements)

13. Drawing J-8982 of Charter Power Systems (C&D), Outline 3DU/DCU-7, 9

14. Drawing M-3792 (C&D) Assembly 3DCU/DU-7,9

15. Data Package Cover Sheet (Test Performance) (Unit 1 Division 3 Battery) — March 23, 1999

16. Data Package Cover Sheet (Test Performance) (Unit 2 Division 3 Battery) — March 28, 1999

17. Tagout Status Sheet — February 28, 1999

18. Temporary Conditions Log/Restoration Verification — February 25, 1999

19. Equalizing Charge Data Sheet (Unit 2 Division 3 Battery) — February 28, 1999

20. Safety Verification Sheet (Unit 2 Division 3 Battery) — February 18, 1999

21. Attachments 4, 5, 6, 7, and 8; Figure 1-10: Typical Battery Capacity During Operational Life (Curves Showing Percent Rated Capacity vs. Percent Battery Life)

22. Letter from C&D Technologies to First Energy/Perry Nuclear Power Plant, "C&D Technologies Battery Model 3DCU-9 Post/Terminal Assembly Details" — February 4, 1999

23. Letter from C&D Technologies to First Energy, "3DCU-09, C&D Field Service #99-73370" — February 11, 1999

24. IE22S005 History of Cell Replacement Unit 1 Division 3 Battery (no date)

25. C&D Vendor Manual

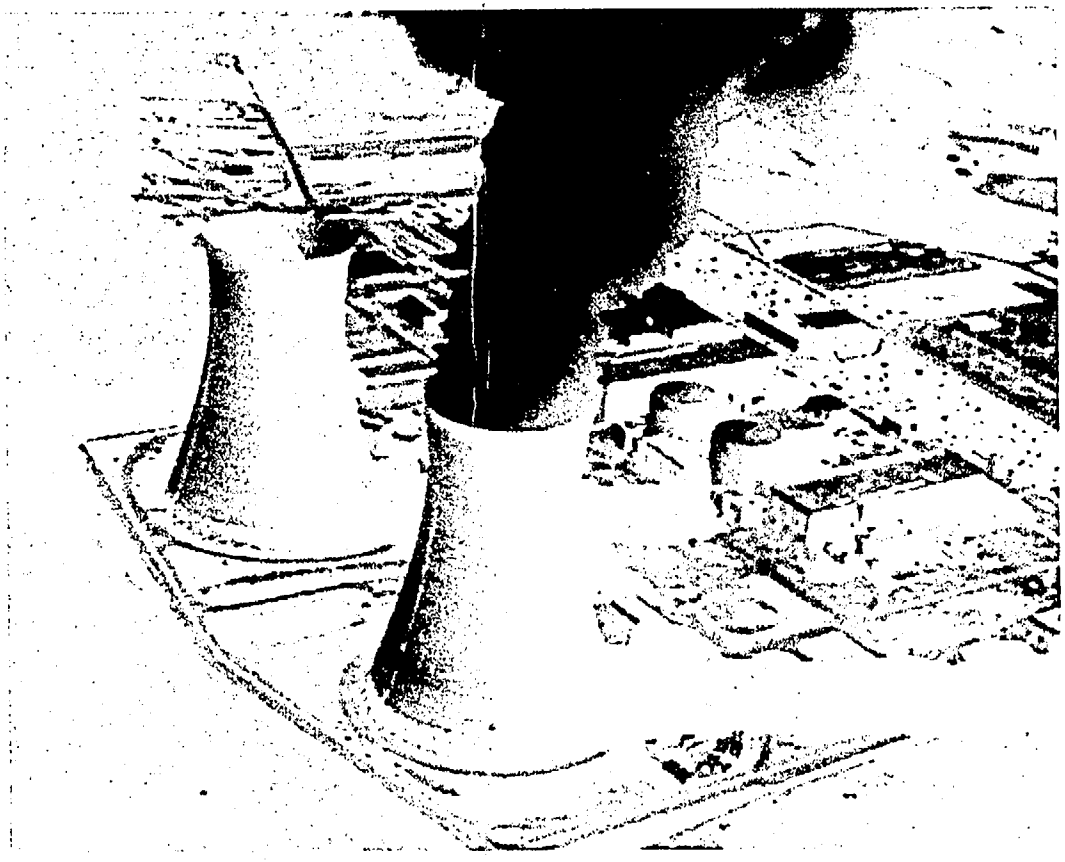
26. (Data Package) Test Performance of Unit 1 Division 3 Performance Test of October 7, 1996 — October 18, 1996

27. (Data Package) Test Performance of Unit 2 Division 3 Battery — March 2, 1999

28. Battery 1E22-S005 Test Data Sheet Unit 1 Division 3 Performance Test — March 9, 1999

NRC/Perry Management Meeting

February 1, 2000



FENOC

FirstEnergy Nuclear Operating Company

Attachment 2

Agenda / Introductions

• Opening Remarks	John Wood
• Management/Employee Alignment	Howard Bergendahl
• Site Human Performance	Bill Kanda
• Operations Performance	Al Rabenold
• Engineering Performance	Bob Schrauder
• NRC Oversight Process	Brian Boles
• Closing	John Wood

Opening Remarks

John Wood

- Meeting Objective
- Current Perry Plant Status
- Perry Year 2000 Key Events
- Perry Vision and Focus

Current Perry Plant Status

- Day 274 of a Planned 656-Day Eighth Operating Cycle
- No Major Equipment Issues
- Two Maintenance Rule (a) (1) Systems
- Small Fuel Defect Determined on 1/4/00 and Suppressed 1/16/00

Perry Year 2000 Key Events

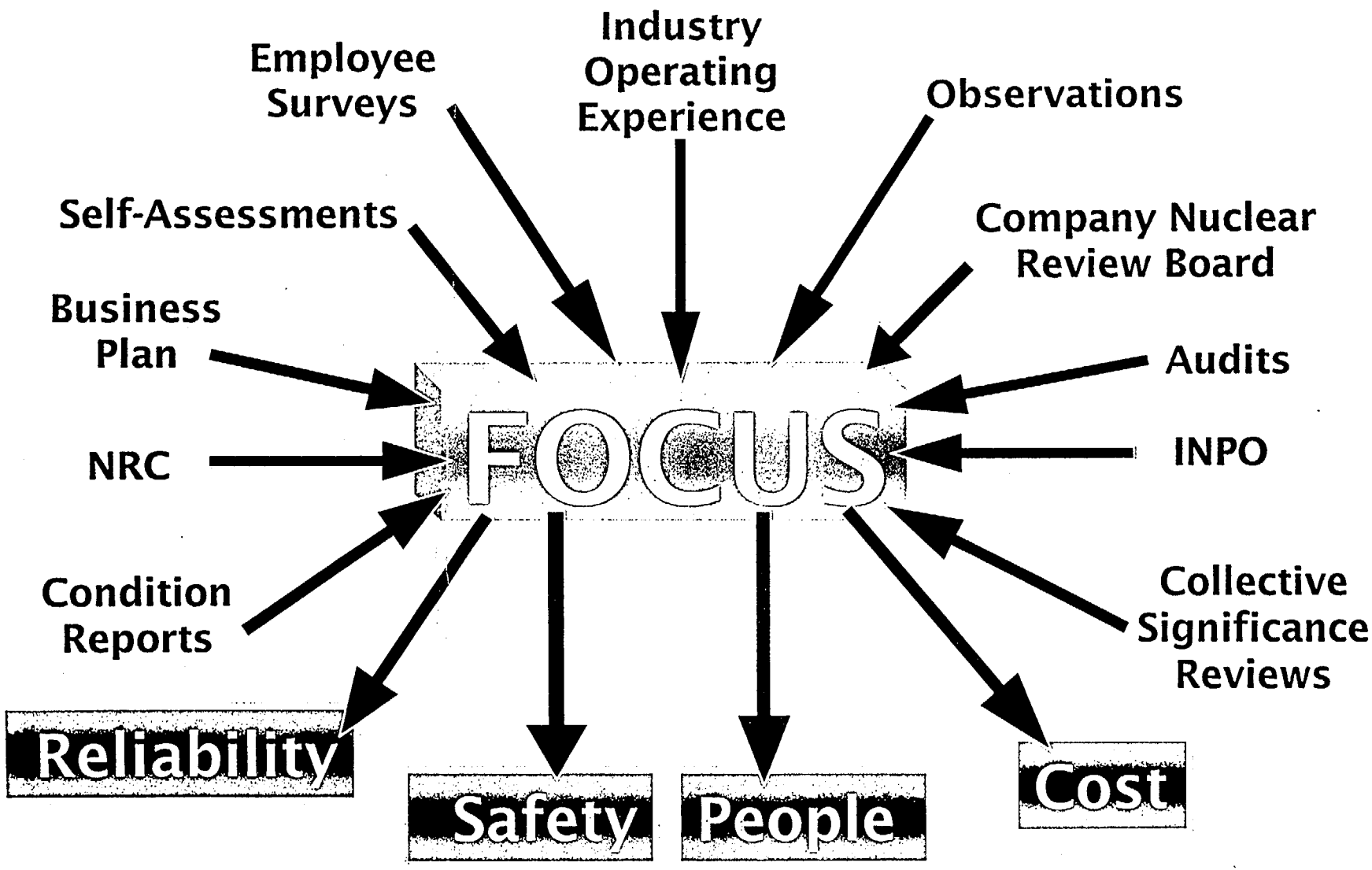
3/21	Emergency Plan Evaluated Exercise
4/1	New NRC Oversight Process
4/3-7	Operational Safeguards Response Evaluation
4/27	Submittal of License Amendment Requests for RFO8
5/8-18	World Association of Nuclear Operators Peer Review
6/7	Perry Readiness for Power Uprate

Ongoing-Refueling Outage 8 Preparations

Perry Vision

- Safe-Reliable-Competitive
- Focus on Operational Excellence
- Forward Not Backward Looking
- Predict & Prevent More Than Find & Fix
- Risk Informed
- Learning Culture

Perry Focus Areas



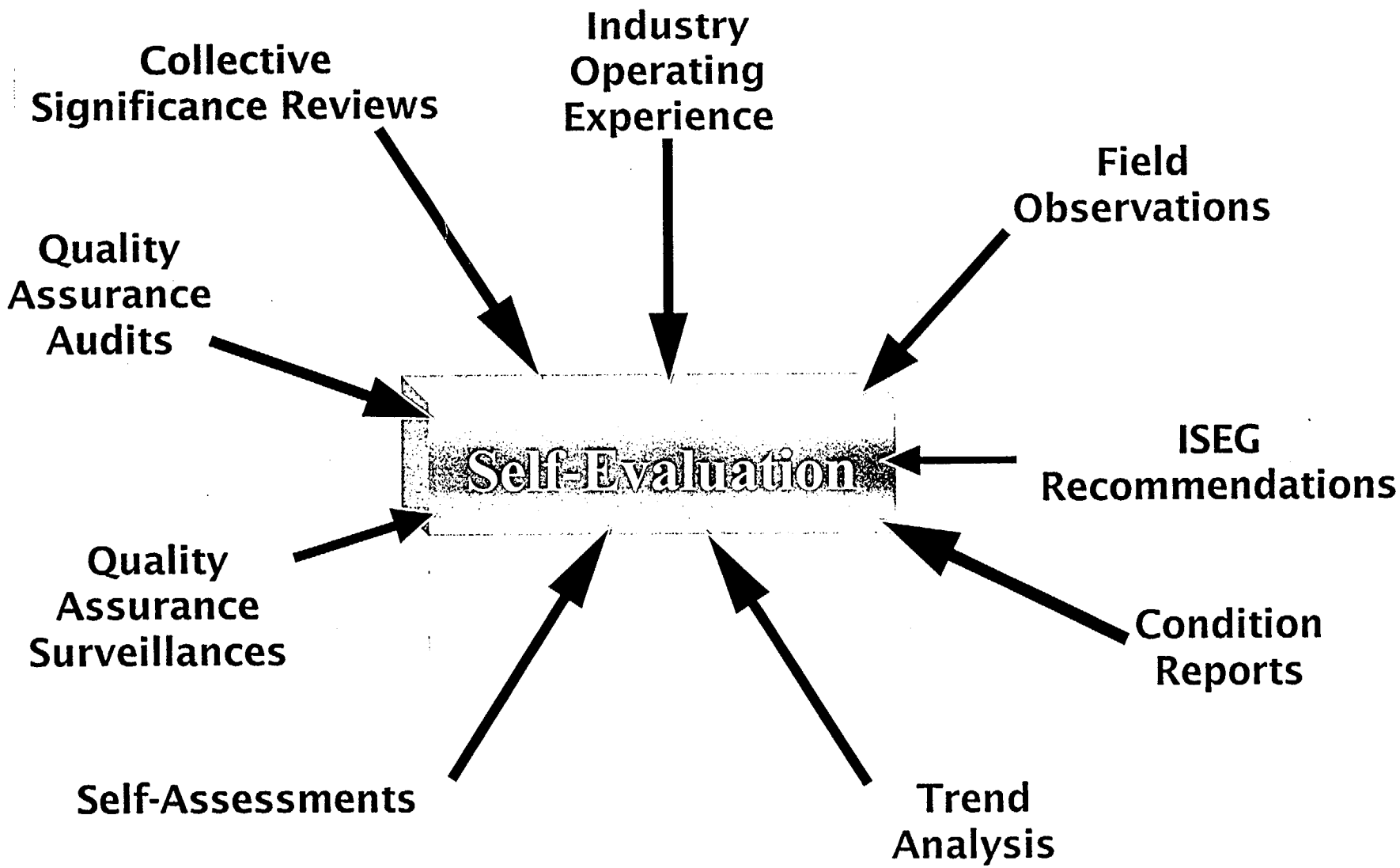
Perry Focus Areas

- Management / Employee Alignment
- Human Performance Error Reduction
- Design Basis Improvement
- **Probabilistic Safety Assessments Applications**
- **Power Uprate**
- **Facilities Improvement**

Management/Employee Alignment

Howard Bergendahl

Performance Improvement Program



Management/Employee Alignment

- Quality Assurance Audit Finding
- Safety Conscious Work Environment/Good
- Category 1 Condition Report
- Root Cause - Inconsistent Communication of Expectations/Inconsistent Accountability
- Employees Uncertain of Management Response
  - Mixed Signals, Workload, Performance Review, Public Review

Management/Employee Alignment

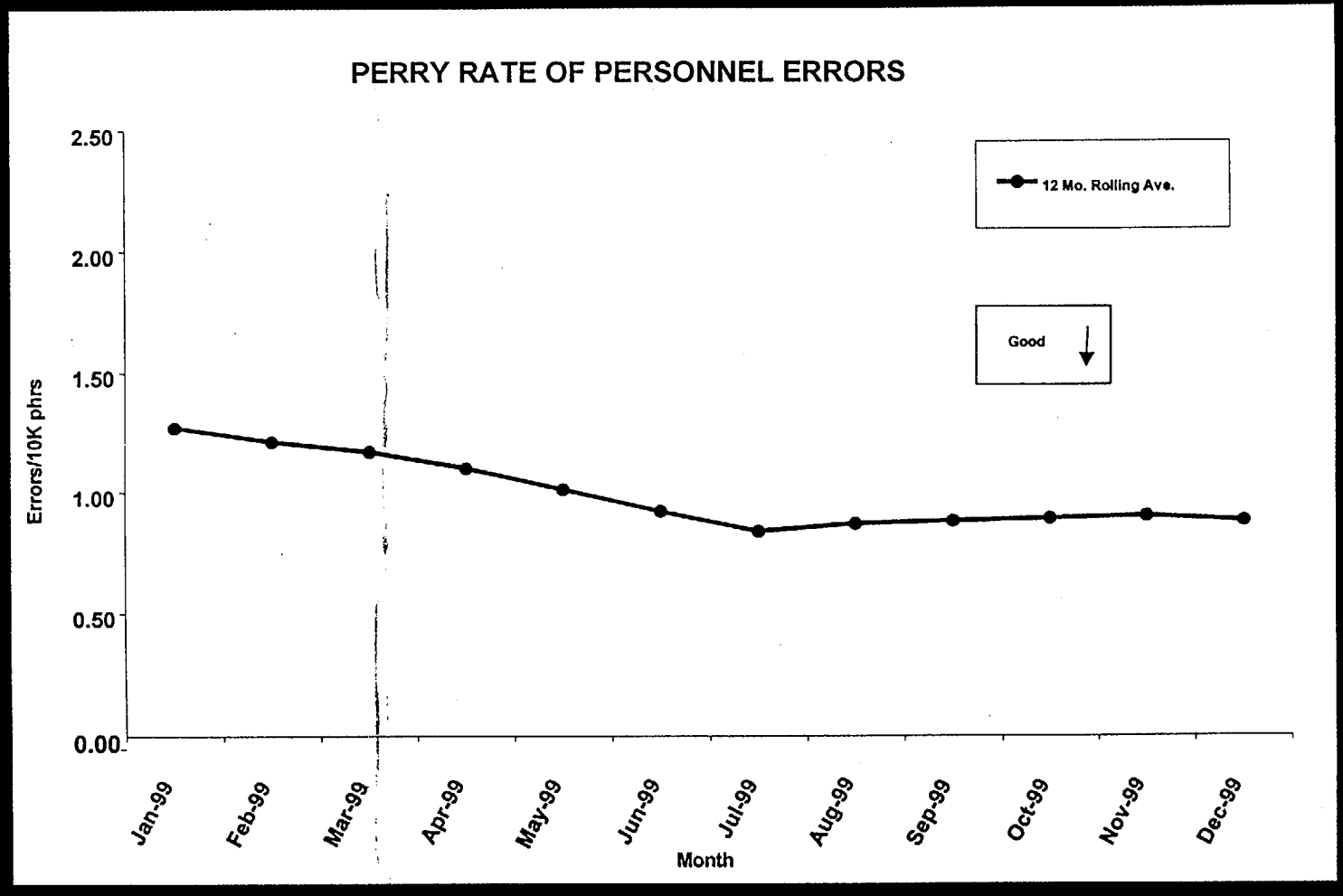
- Face-to-Face Meetings/In-Field Reinforcement/Communication
- Employee Team
  - Best On-Site, Industry, Other Industries
- Evaluate Review Boards
- No Fault Approach
- Culture

Site Human Performance

Bill Kanda

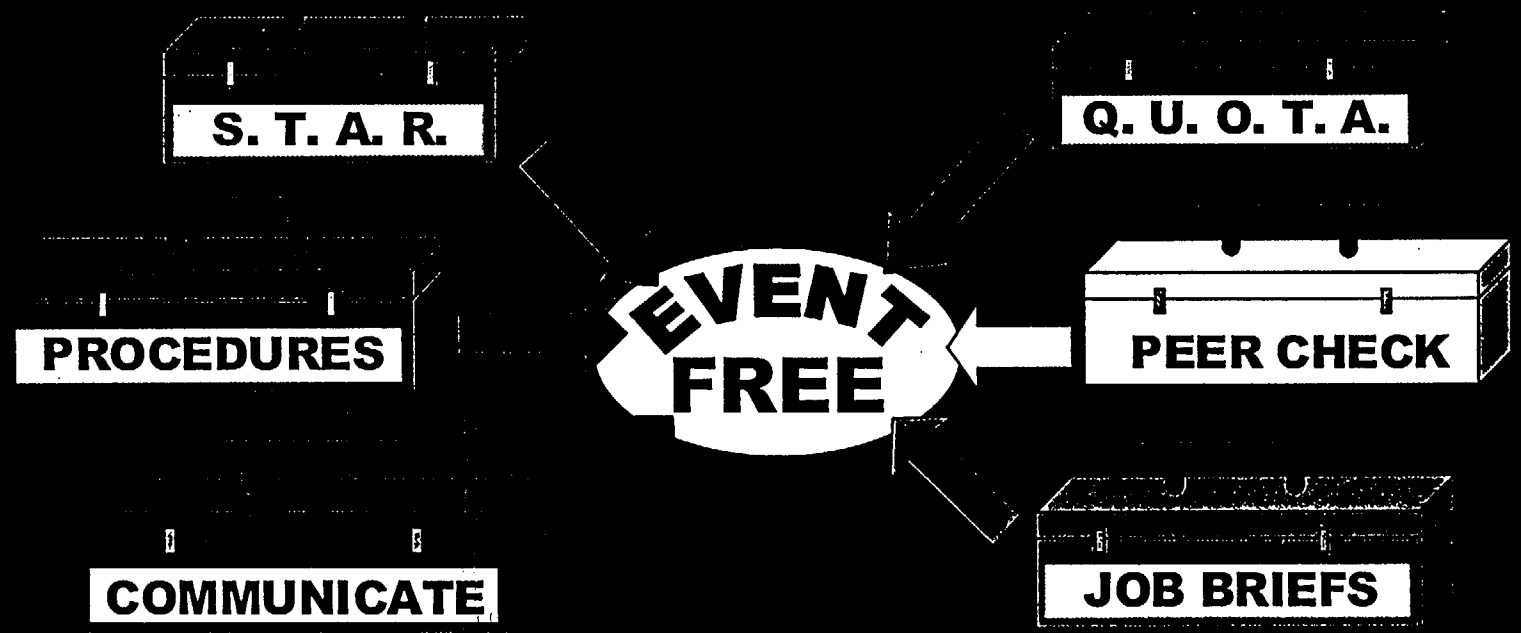
- Human Performance Errors Continue to Occur
- Improvement is Necessary to Prevent Events

Human Performance



- Continued improvement is the challenge

Perry's Tool House



What is Being Done?

- Quarterly Human Performance Enhancements Days
- Industry Involvement in Human Performance
- Implemented Event Free Clock
- Continue Improvement of Field Observation Program

What is Being Done?

- Continuing Human Performance Training
- Self-Assessment - 1st Quarter
- Improve Performance Indicators
- Increase Human Performance Marketing

Challenges In Operations Performance

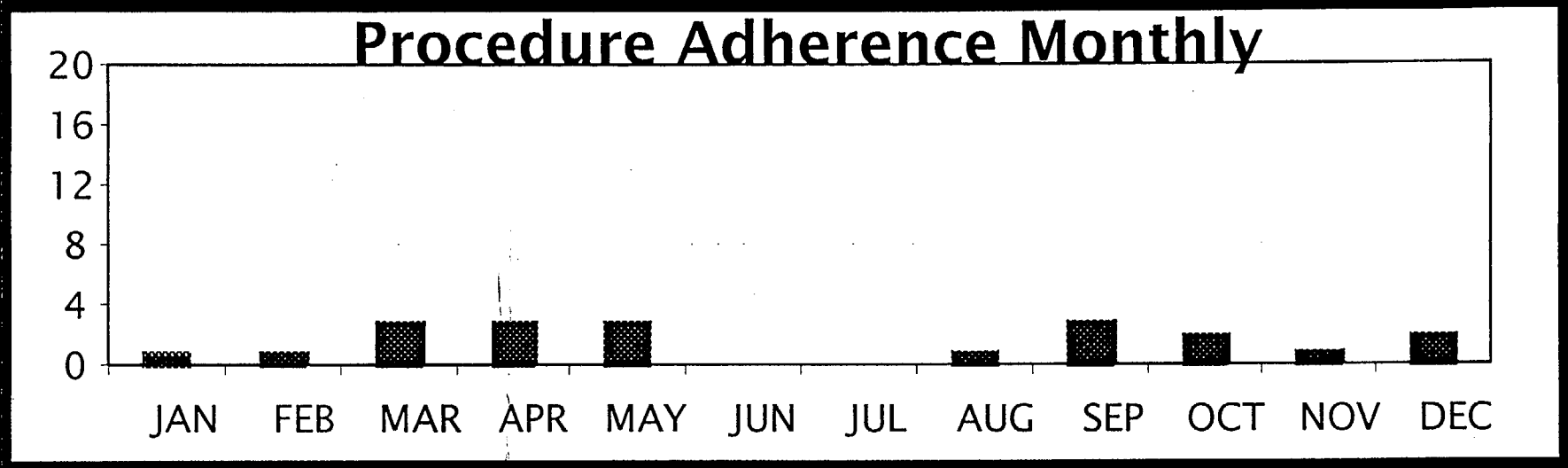
Al Rabenold

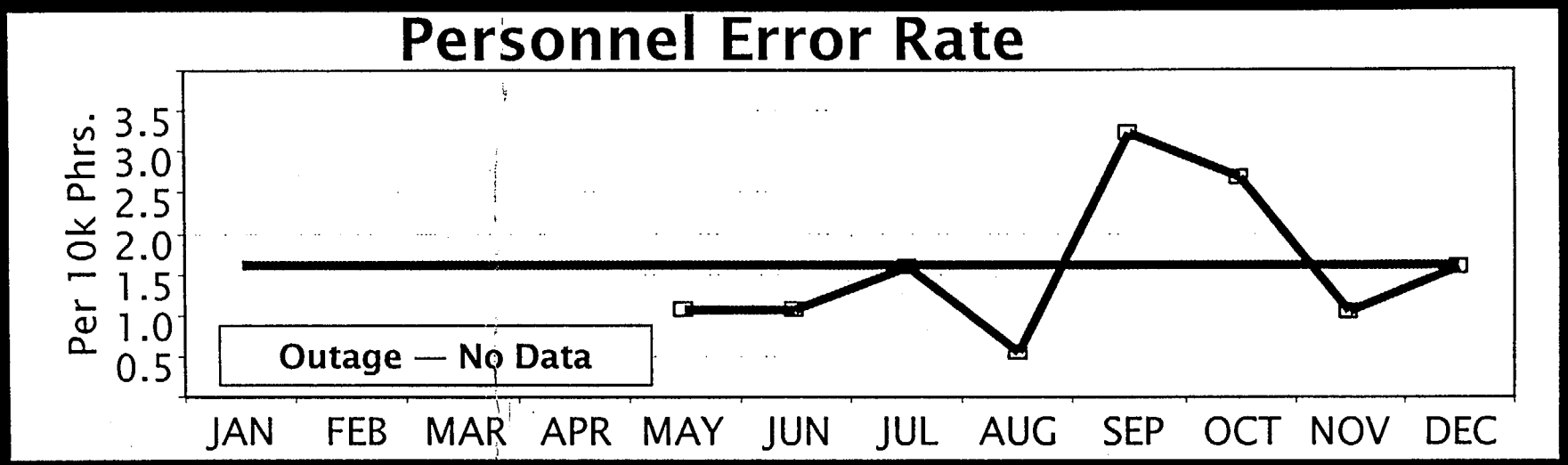
- Human Performance
  - Procedural Adherence
  - Attention to Detail
- Safety Tagging Performance

Human Performance

- Human Performance in Operations Sets Standard for Entire Organization
- Human Performance Goals
  - Less than 0.8 Personnel Errors per 10,000 Person-Hours
  - Less than 6 Procedure Adherence Issues Monthly
  - No Performance Deficiencies Causing a Plant Event

Performance Goals





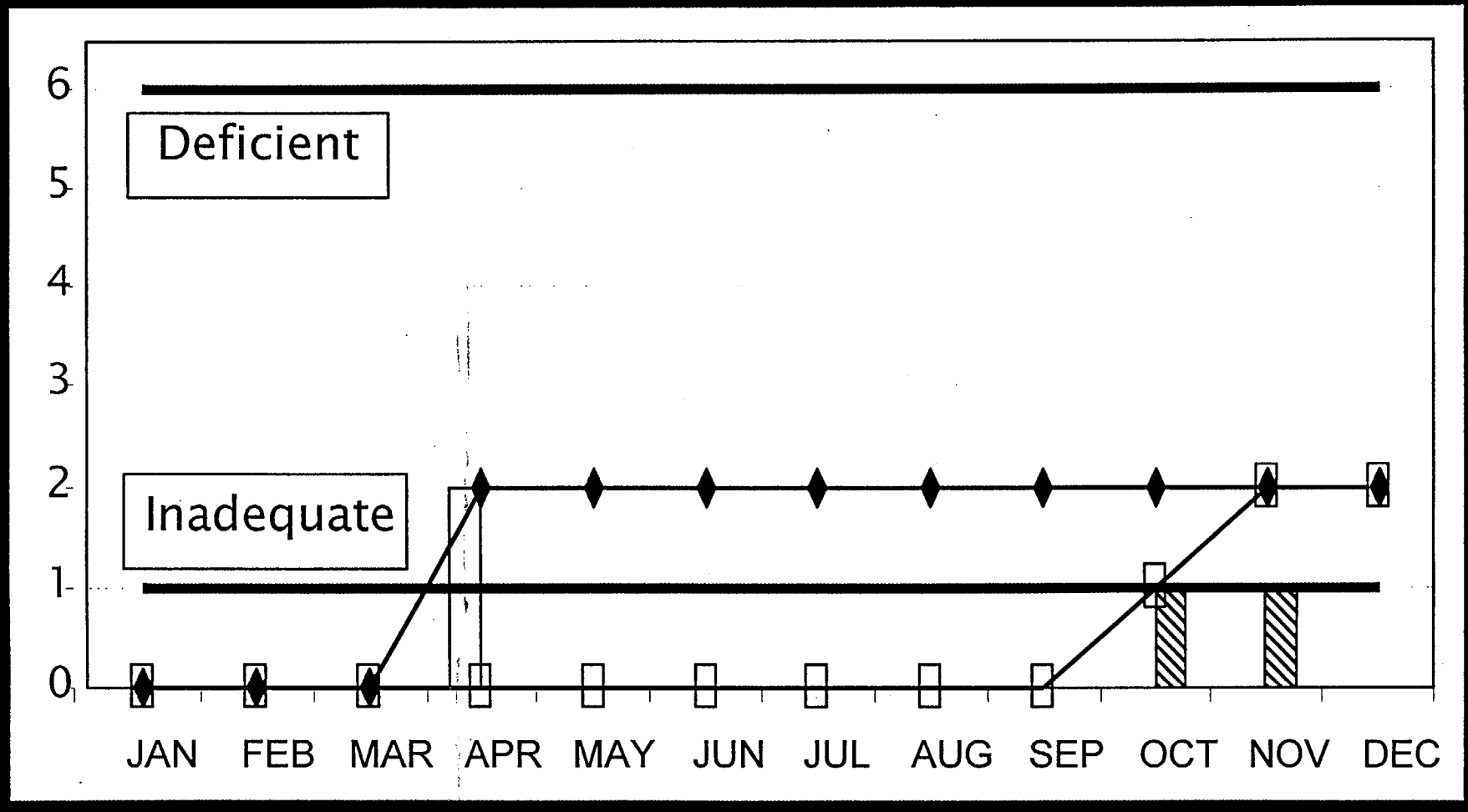
Human Performance Initiatives

- Management/Shift Supervisor One-On-One Discussions
- Work Schedule Assessments
- Increased Management Observations of Control Room Activities
- Enhanced Expectations Handbook Based on Self-Assessment
- Self-Checking/Peer Checking Culture

Safety Tagging Performance

- Issues Noted by Corrective Action Program
- Safety Tagging Issue Categories
  - MINOR - Administrative Error
  - DEFICIENT or INADEQUATE - Risk of Personnel Injury/ Equipment Damage
  - DEFICIENT - Corrected at/before Tag Placement
  - INADEQUATE - Corrected after Tag Placement

Tagging Indicator



Deficient Tagging Issue
Inadequate Tagging Issue
YTD Deficient Tagging Issues
YTD Inadequate Tagging Issues

Tagging Initiatives

- Tagging Unit Training
- Electrical Expertise Restored to Unit
- Maintenance Supervisor Training
- Developing Adequacy Review Tools for Maintenance Supervisors
- Improved Tagging Requests

Engineering Performance

Bob Schrauder

- Design Bases Improvement
- Operability Determinations
- Technical Issues

Design Bases Improvement

- Design Bases Information not Easily Retrievable
  - Impacts Engineering Resources
  - Impacts Timely Issue Resolution
- Resolution: Develop Design Bases Information Documents
  - 15 System Documents Being Developed
  - Other Systems/Topicals as Necessary

Design Bases Improvement

- Calculation Quality Issues Indicated by Corrective Action Program Trending, Self-Assessment, NRC Inspections
  - Attention to Detail/Technical Rigor
  - Voided/Superceded Calculations
  - Open Assumptions
- Resolution
  - Project to Update Calculations with Open Assumptions
  - Calculation Improvement Initiatives

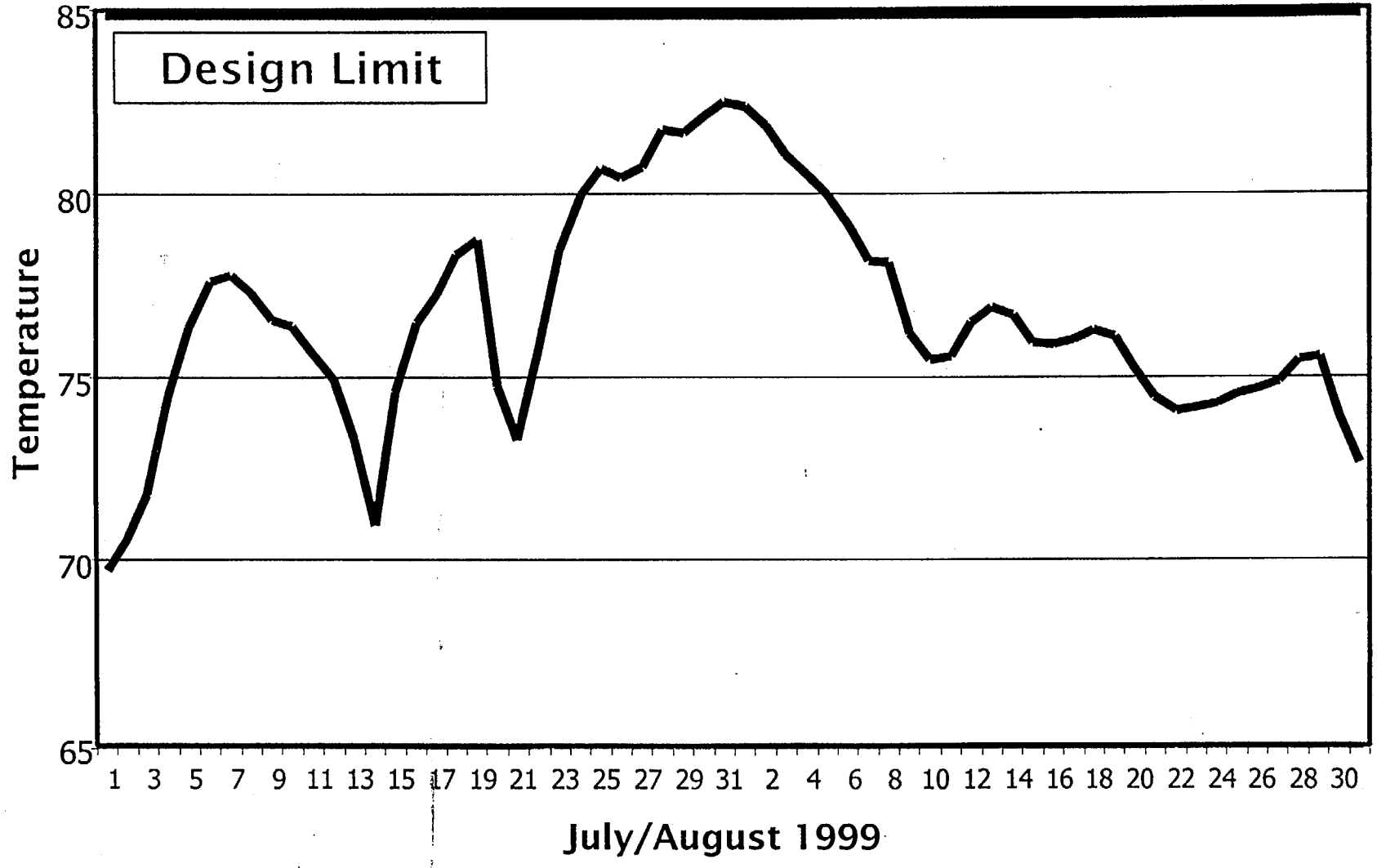
Operability Determinations

- Self-Assessment Conducted Based on Corrective Action Program and NRC Inspections
- Resolution
  - Interim-Management Review Team Established
  - Corrective Action Program Tracks Operability Determinations
  - Process Improvement Team Designated

Technical Issues

- Lake Erie Temperature Record High
- Resolution
  - Fix Leakage Between Cooling Water Return and Cooling Water Suction
  - Evaluate Increasing Safety Related Cooling Water System Temperature

Lake Temperature



Technical Issues

- Tornado Depressurization
- Resolution
  - Compensatory Actions Initiated at Severe Thunderstorm Warning
  - Modifications Implemented/Planned
  - NRC Review Anticipated

Technical Issues

- Inclined Fuel Transfer Blind Flange Removal at Power
- Resolution
  - Category 1 Condition Report
  - ISEG Investigation
  - Continuing Investigation Team

NRC Oversight Process

Brian Boles

- Oversight Process
- Current Status
- Challenges

Process

- April 1 Implementation
- Workshop Participation
- Purpose
  - Maintain Safety
  - Enhance Public Confidence
  - Increase NRC Efficiency/Effectiveness
  - Reduce Regulatory Burden

Perry Performance Indicators

Initiating Events Cornerstone

- Unplanned Scrams per 7000 Critical Hours (PES)
- Scrams with Loss of Normal Heat Removal (PES)
- Unplanned Power Changes per 7000 Critical Hours (PES)

Mitigating Systems Cornerstone

- Safety System Unavailability, Emergency AC Power System (PES)
- Safety System Unavailability, High Pressure Injection System (PES)
- Safety System Unavailability, Heat Removal System (PES)
- Safety System Unavailability, Residual Heat Removal System (PES)
- Safety System Functional Failures (RAS)

Barrier Integrity Cornerstone

- Reactor Coolant System (RCS) Specific Activity (RES)
- Reactor Coolant System Leakage (PES)
- Containment Leakage (PES)

Emergency Preparedness Cornerstone

- Drill/Exercise Performance (PIS EPU)
- Emergency Response Organization Drill Participation (PIS EPU)
- Alert and Notification System Reliability (PIS EPU)

Occupational Radiation Safety Cornerstone

- Occupational Exposure Control Effectiveness (PIS)

Public Radiation Safety Cornerstone

- RETS/ODCM Radiological Effluent Occurrence (PIS)

Physical Protection Cornerstone

- Protected Area (PA) Security Equipment Performance Index (PIS)
- Personnel Screening Program Performance (PIS)
- Compensatory Hours (PIS)

Challenges

- Reduce Complexity
- Balancing Unavailability/Reliability
- Significance Determination Process
- Multiple Performance Indicators
  - NRC/INPO/Maintenance Rule
- Risk Insights

Closing- John Wood

- Plant Running Well and Material Condition is Good
- Challenge is People/Human Performance
- Improved Overall Performance = Focus on People