May 1, 2000

EA 00-065

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

SUBJECT: PERRY INSPECTION REPORT 50-440/2000001(DRP)

Dear Mr. Wood:

On April 1, 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. Engineering department personnel promptly addressed operability questions during the inspection period and provided good support to maintenance and test activities. Routine maintenance and surveillance activities were generally properly coordinated and conducted in accordance with approved procedures. However, there were several human performance issues primarily associated with maintenance activities which occurred during this inspection period. Your staff acknowledged that human performance is a key focus area for the station and that actions had been initiated to address this issue.

Based on the results of this inspection, the NRC has determined that three violations of NRC requirements occurred. The first violation concerns exceeding the Operating License maximum authorized reactor core power level. The second violation concerns the removal of the incorrect relief valve during maintenance work on the Division 3 diesel starting air system. The third violation concerns the ineffective implementation of a corrective action that resulted in the failure to maintain the Division 3 switchgear room temperature within specified values. These violations are being treated as Non-Cited Violations (NCVs), consistent with Section VII.B.1.a of NRC's Enforcement Policy. These NCVs are described in the inspection report. If you contest the violations or severity level of these NCVs, 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.

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Sincerely,

/RA/

Thomas J. Kozak, Chief
Reactor Projects Branch 4

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

Enclosure: Inspection Report 50-440/2000001(DRP)

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J. Wood

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-440
License No:	NPF-58
Report No:	50-440/2000001(DRP)
Licensee:	FirstEnergy Nuclear Operating Company P.O. Box 97 A200 Perry, OH 44081
Facility:	Perry Nuclear Power Plant
Location:	Perry, OH
Dates:	February 16 through April 1, 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 50-440/2000001(DRP)

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

Operations

- The licensee identified that an operator failed to properly evaluate two unexpected annunciators in the control room which were associated with the off gas system vent pipe radiation monitor. An operator assumed that the annunciators were associated with an ongoing maintenance activity rather than being related to a trip of the radiation monitor. Plant management shared the lessons learned with other crews and reinforced the expectations for evaluating and addressing expected and unexpected alarms (Section O1.1).

- The inadvertent disabling of feedwater temperature compensation at the beginning of Cycle 7 resulted in the licensee exceeding the licensed power level of 3579 MWt during two periods of time from February 7 - February 11, 1999, and from February 21 - February 24, 1999, when feedwater heaters had been removed from service. The licensee implemented timely corrective action upon discovery. The highest estimated power level reached during the time period was 102.4 percent. Although it was determined that the Operating License was exceeded, the condition did not result in any actual adverse consequences and was considered to be of low risk significance. One Non-Cited Violation was identified (Section O8.1).

Maintenance

- Emergent equipment issues coupled with the failure to translate anticipated field changes into work orders and limited planned outage staffing led to a planned RCIC system outage taking 87 hours longer than planned. The plant was in a condition of increased risk for most of the time associated with this outage (Section M1.2).

- Several human performance issues have recently occurred during routine maintenance and surveillance testing. The inspectors determined that the items were entered into the licensee’s corrective action program and that plant management was properly addressing the trend. One Non-Cited Violation was identified (Section M1.3).

Engineering

- The inspectors identified that incomplete licensee corrective actions resulted in the Division 3 switchgear rooms not being maintained within the station blackout temperature limits. This condition was identified in 1997 and had not yet been corrected. One Non-Cited Violation was identified (Section E2.1).

Report Details

Summary of Plant Status

The plant began this inspection period with Unit 1 at 100 percent power. The weekly power reductions to 90 percent, implemented January 8, 2000, to perform weekly control rod surveillance testing, continued throughout this inspection period. A power reduction from 100 percent to 70 percent was commenced on February 20, 2000, in order to perform a control rod sequence exchange. The plant returned to 100 percent on February 21, 2000. Another power reduction from 100 percent to 80 percent was performed on March 12, 2000, in order to complete a rod pattern adjustment. Power was returned to 100 percent later that day.

I. Operations

O1 Conduct of Operations

O1.1 Operator Fails to Properly Recognize Unexpected Annunciators

a. Inspection Scope (71707)

The inspectors followed the guidance of Inspection Procedure (IP) 71707 and conducted frequent reviews of plant operations. This included observing routine control room activities, reviewing system tagouts, attending shift turnovers and crew briefings, and performing panel walkdowns. The licensee identified one instance where two control room annunciators were not properly acknowledged; as a result, a failed radiation monitor was not discovered until 2 hours and 40 minutes after the annunciator alarmed.

b. Observations and Findings

On February 15, 2000, during maintenance on the off gas system vent pipe noble gas radiation monitor instrument, the sample skid tripped unexpectedly and caused two alarms in the control room. The control room operator mistakenly declared the alarms “expected” as part of the maintenance activity and did not realize that the sample skid had tripped. After completion of the maintenance activity 2 hours and 40 minutes later, the operators questioned the maintenance technicians as to why the alarms were still in. They then discovered that the sample skid had tripped and properly restored the sample skid to service. During the time that the radiation monitor was unavailable, the Offsite Dose Calculation Manual (ODCM) Table 3.3.7.10-1, items 1.b, 1.c, and 1.e required establishing continuous sample collection within 4 hours. Although the operators did not realize that the monitor was unavailable, the system was restored within approximately 2 hours and 40 minutes and therefore, no ODCM requirements were missed.

Operations management implemented lessons learned to be shared with on-coming crews and CR 00-0453 was issued to investigate the issue. The investigation determined that there were weaknesses in the work planning that should have otherwise identified that the sample skid was likely to be affected by the scope of the maintenance activity. Operations department management also reinforced their expectations for addressing expected and unexpected annunciators in the control room.

c. Conclusions

The licensee identified that an operator failed to properly evaluate two unexpected annunciators in the control room which were associated with the off gas system vent pipe radiation monitor. An operator assumed that the annunciators were associated with an ongoing maintenance activity rather than being related to a trip of the radiation monitor. Plant management shared the lessons learned with other crews and reinforced the expectations for evaluating and addressing expected and unexpected alarms.

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:

- Reactor core isolation cooling (RCIC) system
- Division 3 battery and switchgear rooms (both units)
- Annulus exhaust gas treatment system rooms (both trains)
- Emergency diesel generator rooms (all three divisions)
- Heater bay building
- Turbine power complex
- Auxiliary building
- Intermediate building
- Emergency service water pumphouse building
- 4160 Volt switchgear rooms
- Control rod drive system hydraulic pump rooms

Equipment operability, material condition, and housekeeping were generally acceptable. The licensee was cognizant of a leaking ½" seal line union on the “B” control rod hydraulic pump and was developing a corrective action plan to stop the leak. The inspectors identified that temperatures in the Division 3 switchgear room were not maintained within the limits established in the station blackout evaluation. This issue is discussed in Section E2.1 of this report. The control room operators promptly restored the temperatures within the limits after being notified of this condition by the inspectors. There were no other concerns identified during these walkdowns.

O8 Miscellaneous Operations Issues (92700)

O8.1 (Closed) LERs 50-440/1999-007-00 and 50-440/1999-007-01and URI 50-440/99014-01: On December 16, 1999, the licensee discovered that during the preceding operating cycle, the Perry Plant exceeded its rated power level due to the implementation of a General Electric software change contained in the Cycle 7 core reload design information had disabled feedwater temperature compensation. Feedwater flow is a dominant factor in the accurate determination of reactor thermal power. The venturi feedwater flow measurement 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 power (i.e., conservative) and at feedwater temperatures below 420 °F, the calculated reactor thermal power is less than the actual power (i.e., non-conservative). 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 power, 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 investigations disclosed that during two periods of time at the end of Cycle 7, following the deliberate removal of feedwater heaters from service, steady state plant operation exceeded the licensed power level of 3579 MWt with the plant remaining at an indicated power level of 3579 MWt. The first period occurred on February 7, 1999, and lasted approximately 76 hours. The greatest estimated power level reached during this period was 3623 MWt (101.23 percent). The second period occurred on February 21, 1999 and lasted approximately 71 hours. During this period, steady state operation exceeded 102 percent of licensed power level twice, the first time for an approximately 1 hour period with the highest estimated power level reaching 3657 MWt (102.2 percent) and the second time for approximately one hour and twenty minutes with the highest estimated power level reaching 3653 MWt (102.1 percent). In addition to these periods, there were four other 10 minute periods where actual power exceeded 102 percent. It was during one of these periods that the overall highest estimated power of 3664 MWt (102.4 percent) was reached.

In response to this issue, the licensee: a) reduced reactor power to 98 percent; b) notified the NRC that an error existed in the plant's thermal power calculation and that licensed thermal power may have been exceeded as a result; c) issued written guidance to the control room staff regarding APRM calibrations and thermal limits; d) reviewed other applications to ensure that the disabled temperature array was not used for anything other than the heat balance; e) independently confirmed that the temperature effect on feedwater flow measurement is conservative above 420 °F and non-conservative below 420 °F; f) contacted General Electric to review the basis of the constants and verify that they could be restored to their original values; g) reviewed other parameter/constant changes that were included in the suspect software change package to ensure there were no other effects; h) submitted an operating experience (OE) report to the industry; and i) reviewed the work history on the venturi flow elements and their transmitters to verify that no work had been done that would cause venturi parameters to change.

The licensee's subsequent investigation identified the following three root causes: 1) plant procedure FTI-G0003, "Fuel Management Analysis Activity" did not adequately control review of changes to the 3D Monicore databank for fuel cycle updates; 2) Plant Administrative Procedure (PAP)-0506, "Computer Software Administration Control" requirements for maintaining the 3D MONICORE Software Design Description were not followed; and 3) the software change description template used for the Cycle 7 databank did not provide adequate details of the change such as how it affected the feedwater temperature compensation.

In addition to the three root causes, the licensee's investigation identified several contributing causes. The inspectors noted that the final approved investigation contained remedial corrective actions as well as corrective actions to preclude recurrence. These actions were reviewed and considered to be adequate by the inspectors.

This event did not have any actual consequences due to the existence of ample margins to the Technical Specification operating limits during the periods of time that power exceeded 100 percent and the event was considered to have low risk significance. However, the two periods of time from February 7 - February 11, 1999, and from February 21 - February 24, 1999, when the steady state plant power level exceeded the licensed power level of 3579 MWt, is a violation of the Perry Operating License, Section 2.C.(1) which authorizes the licensee to operate the facility at reactor core power levels not in excess of 3579 megawatts thermal (MWt). 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 99-3133 **(NCV 50-440/2000-001-01 (DRP))**.

O8.2 <u>(Closed) LER 50-440/2000-002, Rev 0</u>: Inadequate Data Validation Checks Result in Missed Power Distribution Limits Surveillance Requirements. On March 1, 2000, the licensee identified that the 3D MONICORE report was using static (historical) data rather than current plant data to calculate thermal limits. The 3D MONICORE report was used to conduct Technical Specification (TS) Surveillance Requirements (SRs) 3.2.1.1, 3.2.2.1, and 3.2.3.1, which require that certain power distribution limits be calculated every 24 hours. The licensee determined that the historical data was used for 55 hours during the calculation of power distribution limits. The cause for this condition was determined to be an inadequate software design that inadvertently allowed historical data to be used in power distribution calculations after a computer shutdown and restart. Plant management implemented immediate corrective actions, including promptly conducting the required surveillance tests, providing additional guidance to operators to enable them to discern when the computer could be using static data, and requesting a review to determine whether there were other similar software deficiencies. A software change was completed to correct the deficiency. During the period of time when the computer was using historical data, the plant was in a steady-state at full power. Reactor engineering personnel reviewed the available data for the time period when the surveillance tests were missed and determined that an adequate margin to thermal limits was maintained. The failure to adequately conduct the surveillance tests required every 24 hours by TS SRs 3.2.1.1, 3.2.2.1, and 3.2.3.1 is a violation. However, this was an isolated failure to implement a requirement that had no programmatic implications and no safety impact. The delay in calculating the power distribution limits was not significant. This failure constitutes a violation of minor significance and is not subject to formal enforcement action.

II. Maintenance

M1 Conduct of Maintenance

M1.1 <u>Review of Routine Maintenance and Surveillance Activities</u>

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

- Work Order (WO) 00-2426, replace reactor core isolation cooling (RCIC) flow controller
- Surveillance Instruction (SVI)-E51-T2001, "RCIC System Pump and Valve Operability Test"

- SVI-M17-T2002, “Containment Vacuum Breaker and Isolation Valve Operability Test,” post-maintenance test for WO 00-1260 on containment vacuum breaker M17-F030

- SVI-M51-T2003, “Combustible Gas Mixing System B Operability Test”

- WO 99-20307, replace pillow block bearings on annulus exhaust gas treatment system (AEGTS) “A” pump

- WO 00-2397, troubleshoot/rework C85 power supply PS21

- Removal of clearance tags hung under Tagout #33807 which had been hung to support WO 00-3373, repack 1N11F0165A

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

M1.2 RCIC System Outage Extended Beyond Planned Duration

a. Inspection Scope (62707)

The inspectors followed the guidance of IP 62707 in reviewing scheduled maintenance on the RCIC system. This review included attending maintenance coordination meetings and briefings, reviewing activities in the field, and observing portions of post maintenance testing and surveillance testing.

b. Observations and Findings

The licensee had planned an 18 hour RCIC system outage to commence and end on February 28, 2000, primarily to replace the lube oil and a lube oil relief valve. The plant was in a condition of increased risk most of the time that RCIC system was unavailable. The licensee ran into several problems during the RCIC system outage, including:

- The old lube oil system drain plug threads were worn and a new drain plug needed to be ordered and dedicated. This was not identified until the outage was already in progress and caused a slight delay.

- The new relief valve was physically different from the old one. Although the differences were recognized by engineering personnel well ahead of time, the work documents did not adequately address the need to make piping changes in the field. Once the need for additional work was recognized, engineering department personnel provided guidance to maintenance personnel for making the necessary changes, however, this delayed completion of the lube oil piping work.

- Because the original scope and duration of the RCIC system work did not appear to warrant around-the-clock coverage, maintenance and engineering support personnel were not staffed to cover the RCIC work on the night shift until February 29, 2000.

- During post-maintenance testing on March 1, 2000, the RCIC system pump turbine tripped on high turbine exhaust pressure. This unexpected condition resulted in additional out-of-service time while engineering and maintenance personnel conducted troubleshooting to address the cause and correct the condition.

- Erratic readings were provided from the steam flow high leak detection instrument. Additional RCIC out of service time was required to back fill, replace, calibrate, and test the instrument. The licensee conducted this work before declaring the system operable.

- During the surveillance test on March 2, the flow controller limited the maximum rpm for the turbine which precluded the turbine from reaching the required reference range specified in the SVI. The flow controller was replaced and the SVI was conducted satisfactorily.

The RCIC system was returned to service and declared operable on March 3, 2000. The total out of service time was actually 105 hours, instead of the 18 hours planned. The licensee initiated several condition reports (00-592, 00-603, 00-609, and 00-610) to address the unexpected equipment issues and document the delays in completing the outage as scheduled. Additionally, the licensee conducted a critique of the maintenance activities on March 7, 2000. During the critique, the licensee concluded that there were several missed opportunities in pre-job planning and coordination, and that there were lessons-learned that needed to be implemented in order to more effectively manage plant risk and equipment unavailable time.

c. Conclusions

Emergent equipment issues coupled with the failure to translate anticipated field changes into work orders and limited planned outage staffing led to a planned RCIC system outage taking 87 hours longer than planned. The plant was in a condition of increased risk for most of the time associated with this outage.

M1.3 Recent Trend in Human Performance Issues During Maintenance Activities

a. Inspection Scope (61726, 62707)

The inspectors reviewed several recent human performance issues that occurred during the performance of routine maintenance and surveillance testing. The inspectors reviewed operator logs, associated CRs, and held discussions with involved personnel.

b. Observations and Findings

During this inspection period, there were several instances of human performance issues within the maintenance department. These issues were either licensee-identified or self-revealing. The inspectors determined that this recent trend was a departure from routine performance. The inspectors observed that licensee management properly addressed each issue as it was discovered and reset the plant's "Event-Free Clock" where appropriate. The issues are briefly described below.

- On March 1, 2000, following an off gas treatment system hydrogen analyzer surveillance test, an error was made during the final system valve lineup which resulted in the analyzer sampling nitrogen gas rather than the off gas treatment system. Nitrogen gas is supplied to the hydrogen analyzer through valve manipulations during calibrations. The error was identified on March 6, 2000, when the nitrogen supply was exhausted and a trouble alarm (low nitrogen flow) was received in the control room. The control room operators declared the hydrogen analyzer inoperable and entered Operational Requirements Manual (ORM), Section 6.2.11, which requires that grab samples be obtained once every 4 hours when the hydrogen analyzer is inoperable. The results of the grab samples indicated that hydrogen levels in the off gas treatment system were normal.

  Technical Specification 5.4.1.d requires that procedures be implemented covering programs specified in TS 5.5. Technical Specification 5.5.8 requires that a program be implemented to limit hydrogen concentrations in the main condenser off gas treatment system. Operational Requirements Manual 6.2 is used to limit hydrogen concentrations in the main condenser off gas system and ORM, Section 6.2.11, requires that grab samples be obtained every four hours from the off gas treatment system when the hydrogen analyzer is inoperable. This requirement was not met from March 1 to March 6, 2000, while the hydrogen analyzer was inoperable. The failure to meet this requirement is a violation of TS 5.4.1.d. However, this failure was not significant in that it was an isolated failure to implement a requirement that had no programmatic implications and no safety impact. This failure constitutes a violation of minor significance and is not subject to formal enforcement action.

- On March 13, 2000, Work Order 99-8321 was approved to replace relief valve 1E22F0539A which was associated with the Division III emergency diesel generator starting air dryer skid. However, a mechanic incorrectly removed relief valve 1E22F0569A. Technical Specification 5.4.1.a requires that written procedures be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide (RG) 1.33, Revision 2, Appendix A, dated February 1978. Section 9 of Appendix A to RG 1.33 recommends that procedures be developed and implemented for performing maintenance that can affect the performance of safety-related equipment. Work Order 99-8321 was used during the performance of maintenance on safety-related equipment. The failure to comply with the instructions in Work Order 99-8321 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 of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as CR 00-0767 **(NCV 50-440/2000-001-02 (DRP))**.

- On March 16, 2000, WO 99-020307 was approved to replace the coupling and shaft bearings on the "A" annulus exhaust gas treatment system (AEGTS) pump. Step 004.1 of the work order required that the pillow block setscrews be torqued upon completion of the coupling and bearing replacements. Maintenance personnel informed the Operations Unit Supervisor that the work had been completed and the system was declared to be operable at 0600 hours on March 16, 2000. During subsequent discussions between offgoing and oncoming maintenance personnel, it was identified that the setscrews had not been torqued as required by the WO. This was communicated in a timely manner to the Unit Supervisor who returned the “A” AEGTS to an inoperable status at 0645 hours on March 16, 2000. The setscrews were torqued at 1030 hours the same day and the “A” AEGTS was declared operable shortly thereafter. Technical Specification 5.4.1.a requires that written procedures be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide (RG) 1.33, Revision 2, Appendix A, dated February 1978. Section 9 of Appendix A to RG 1.33 recommends that procedures be developed and implemented for performing maintenance that can affect the performance of safety-related equipment. Work Order 99-020307 was used during the performance of maintenance on safety-related equipment. The failure to comply with the instructions in Work Order 99-020307 is a violation of TS 5.4.1.a. However, this failure was not significant in that it was an isolated failure to implement a requirement that had no programmatic implications and no safety impact. This failure constitutes a violation of minor significance and is not subject to formal enforcement action.

c. Conclusions

Several human performance issues have recently occurred during routine maintenance and surveillance testing. The inspectors determined that the items were entered into the licensee’s corrective action program and that plant management was properly addressing the trend. One Non-Cited Violation was identified.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Division 3 Switchgear Room Temperatures Not Maintained Within Station Blackout (SBO) Evaluation Assumptions

a. Inspection Scope (37551, 71707)

During plant tours, the inspectors identified that the Unit 1 Division 3 switchgear room temperature was higher than that assumed in the licensee’s Station Blackout evaluation. The inspectors followed the guidance in IP 37551 and 71707 in reviewing related documentation, operator rounds, the Updated Safety Analysis Report (USAR), and the System Operating Instruction (SOI).

b. Observations and Findings

On February 15, 2000, the licensee declared the Unit 2 (backup) Division 3 battery inoperable due to low temperatures in the room. The inspectors walked down both the Unit 1 and Unit 2 Division 3 battery and switchgear rooms and noted that the temperature was approximately 80 °F in the Unit 1 switchgear room. The inspectors questioned the control room operators on whether there was an upper limit for system operability. The operators indicated that there was no limit. The inspector reviewed the annunciator response procedure and the SOI for the system. There was no discussion of a maximum temperature limit. The inspector reviewed the licensee’s SBO submittal, dated April 17, 1989 and PIF 97-0266, which was written to address the need for an upper temperature limit. The calculation referenced in the PIF stated that the maximum room temperature assumed in the SBO evaluation was 77.3 °F. The inspectors reviewed the plant operator logs and determined that the temperatures had been between 80 °F and 82 °F during the previous week and informed the Operations Superintendent of this issue. After consultation with engineering personnel, the control room operators restored the temperature in the Unit 1 Division 3 switchgear room to 77 °F and initiated a Standing Instruction to alert the operators to this limit. A condition report was initiated and the licensee reset the Event-Free Clock.

Upon further review of PIF 97-0266, the inspectors identified that one of the corrective actions specified in the PIF was to update the SOI to provide an upper limit for battery room temperature. Although an Operation Manual Change Request was apparently initiated, the SOI had not been updated. PIF 97-0266 was specifically written to address the identified condition adverse to quality that the battery/switchgear rooms were not being maintained within the SBO temperature limits. Criterion XVI of 10 CFR 50, Appendix B, requires that conditions adverse to quality be promptly identified and corrected. The failure to promptly correct this condition adverse to quality is a violation of 10 CFR 50 Appendix B Criterion XVI. 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 00-0474. **(NCV 50-440/2000-001-03(DRP))**

c. Conclusions

The inspectors identified that incomplete licensee corrective actions resulted in the Division 3 switchgear rooms not being maintained within the temperature limits stated in the licensee's station blackout analysis. This condition was identified in 1997 and had not yet been corrected. One Non-Cited Violation was identified.

E8 Miscellaneous Engineering Issues (92700)

E8.1 (Closed) Licensee Event Report (LER) 50-440/1999-003-00: Post-Accident Dose Limits Exceeded for Relief Valve Leakage Outside of Containment. On February 18, 1999, the licensee identified that a residual heat removal system relief valve was leaking at a rate of 135 gallons per hour which exceeded the operating limit for leakage outside containment. At the time the leakage was identified, plant operators promptly corrected the condition to minimize the time that the plant was in a degraded condition. Initially, the licensee did not properly report the condition to the NRC as required by 10 CFR 50.73(a)(2)(ii). This was identified by the NRC in Inspection Report 50-440/99013 and dispositioned as a Non-Cited Violation (99013-04(DRS)). The licensee subsequently reported the condition and the relief valve was removed from the system on September 13, 1999, as part of a modification. This item is closed.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management on March 22, 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 included in this report.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

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H. Bergendahl, Director, Nuclear Services Department
B. Boles, Manager, Plant Engineering
N. Bonner, Director, Nuclear Maintenance Department
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R. Schrauder, Director, Nuclear Engineering Department
J. Sears, Manager, Radiation Protection

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 92902:	Followup - Maintenance
IP 93702:	Prompt Onsite Response to Events at Operating Power Reactors

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-440/2000-001-01	NCV	Exceeding the Maximum Authorized Reactor Core Power Level
50-440/2000-001-02	NCV	Removal of the Wrong Relief Valve During Maintenance work on the Division 3 Diesel Starting Air System
50-440/2000-001-03	NCV	Ineffective Implementation of a Corrective Action That Resulted in the Failure to Maintain the Division 3 Switchgear Room Temperature Within Specified Values

Closed

50-440/1999-003-00	LER	Post-Accident Dose Limits Exceeded for Relief Valve Leakage Outside of Containment
50-440/1999-007-00	LER	Operating License Thermal Power Limits Exceeded
50-440/1999-007-01	LER	Operating License Thermal Power Limits Exceeded, Rev 1
50-440/2000-002-00	LER	Inadequate Data Validation Checks Result in Missed Power Distribution Limits Surveillance Requirements
50-440/99014-01	URI	Review of Licensee’s Investigation of CR 99-3133 for Exceeding Operating License Thermal Power Limit
50-440/2000-001-01	NCV	Exceeding the Maximum Authorized Reactor Core Power Level
50-440/2000-001-02	NCV	Removal of the Wrong Relief Valve During Maintenance work on the Division 3 Diesel Starting Air System
50-440/2000-001-03	NCV	Ineffective Implementation of a Corrective Action That Resulted in the Failure to Maintain the Div. 3 Switchgear Room Temperature Within Specified Values

Discussed

None

LIST OF ACRONYMS USED

AEGTS	Annulus Exhaust Gas Treatment System
CFR	Code of Federal Regulations
CR	Condition Report
DRP	Division of Reactor Projects
IP	Inspection Procedure
IR	Inspection Report
LCO	Limiting Condition for Operation
LER	Licensee Event Report
MWt	Megawatts Thermal
NCV	Non-cited Violation
NRC	Nuclear Regulatory Commission
ODCM	Offsite Dose Calculation Manual
ORM	Operations Requirements Manual
PAP	Plant Administrative Procedure
PERR	Public Electronic Reading Room
PIF	Potential Issue Form
RCIC	Reactor Core Isolation Cooling
SOI	System Operating Instruction
SR	Surveillance Requirements
SVI	Surveillance Instruction
TS	Technical Specification
URI	Unresolved Item
USAR	Updated Safety Analysis Report
WO	Work Order