U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-440
License No:	NPF-58
Report No:	50-440/98016(DRP)
Licensee:	Centerior Service Company P.O. Box 97, A200 Perry, OH 44081
Facility:	Perry Nuclear Power Plant
Location:	Perry, Ohio
Dates:	July 23 through September 8, 1998
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EXECUTIVE SUMMARY

Perry Nuclear Power Plant
NRC Inspection Report 50-440/98016(DRP)

This inspection report includes resident inspectors' evaluation of aspects of licensee operations, engineering, maintenance, and plant support.

Operations

- The inspectors concluded that operations department personnel demonstrated a good questioning attitude when assessing the validity of the surveillance data for the hydrogen recombiners (HR) when initial resistance-to-ground readings did not meet the acceptance criterion of the surveillance test. Also, the on-shift operating crew made the appropriate Technical Specifications entries based on their assessment of the HR test results (Section O1.2).

- Operations department personnel took prompt and effective actions in response to the automatic isolation of a feedwater heater, equipment problems associated with shifting reactor recirculation system flow control valve hydraulic control subloops, and the failure of an average power range monitor post-maintenance test. The operators effectively interacted during the events with open communications between all levels of the on-shift operating crews. The operators quickly identified and responded to the situations and initiated corrective action documents in accordance with licensee management expectations (Section O1.3).

- The inspectors determined that while most shift turnover briefings were effective, the quality of the briefings varied from crew to crew. For example, at various briefings, some operators were not sufficiently prepared to discuss watch station status, ambiguous terminology was used to discuss equipment status, and some attendees were unable to hear each speaker (Section O1.4).

Maintenance

- The inspectors concluded that the licensee was proactive in replacing a degraded emergency service water pump in a planned outage prior to its failure. While the outage was completed within the allotted time in the applicable Technical Specification limiting condition for operation, better planning for the outage could have resolved pump shaft design differences and could have reduced the on-line out-of-service time for safety-related equipment (Section M1.2).

- The inspectors determined that the licensee effectively incorporated probabilistic risk assessment (PRA) techniques into daily plant operations. For example, a shift supervisor (SS) requested a new PRA value for the potential loss of an emergency service water isolation valve after it was discovered that the valve may not open due to missing gear teeth. The SS questioned the initial PRA value that was provided and a recalculation of the value resulted in the identification that the risk category was actually medium as opposed to low for this condition (Section M1.3).

Engineering

- The inspectors concluded that engineering department personnel were promptly involved in the testing activities and thoroughly pursued the resolution of the proper testing methodology for the HRs. The inspectors considered that there was good supervisory and senior management oversight during problem discovery, investigation, and resolution of this issue (Section O1.2).

- The licensee performed a comprehensive root cause evaluation of the two reactor core isolation cooling turbine trips and identified that governor valve stem binding was the root cause of the trips. The information developed through this evaluation was appropriately disseminated to the industry (Section E8.6).

Plant Support

- The inspectors determined that the operations superintendent appropriately questioned an operator's radiological practices when manipulating equipment and interfacing with fluid in a potentially contaminated system during control rod drive hydraulic control unit (HCU) venting activities. The licensee initiated timely actions in analyzing the radioactive activity level of the HCU fluid which was below that which required protective clothing. The inspectors concluded that the operations superintendent took proactive actions by instituting an enhanced radiation protection practice requiring operators to wear protective gloves when conducting these and similar activities that breach the HCUs (Section R1.1).

- The inspectors concluded that the fire protection supervisor implemented effective corrective actions for two fire extinguishers which had been temporarily stored beyond the guidance allowed in the station's housekeeping procedure. However, a condition report was not initiated for this issue until the inspectors identified that licensee management's expectations were not met regarding entering this information into the corrective action program (Section O2.1).

Report Details

Summary of Plant Status

The plant was operating at 100 percent power at the start of this inspection period. On August 20, 1998, operators reduced power to 95 percent in response to a feedwater heater isolation event. The plant was operated at 100 percent power at all other times, with the exception of minor power reductions for routine rod sequence exchanges and turbine valve testing.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

The inspectors followed the guidance of Inspection Procedure 71707 and conducted frequent reviews of plant operations. This included observing routine control room activities, reviewing system tagouts, attending shift turnovers and crew briefings, performing panel walkdowns and observing operators respond to equipment malfunctions. The inspectors concluded that the overall conduct of operations continued to be professional, with appropriate safety focus. Specific observations are discussed below.

O1.2 Good Licensee Involvement In Resolving the Adequacy of Surveillance Testing for the Hydrogen Recombiners

a. Inspection Scope (71707, 37551)

On July 16, 1998, the inspectors reviewed the licensee's response and follow up activities associated with questionable test results of the "A" HR. The inspectors reviewed the applicable documentation and interviewed operations and engineering personnel.

b. Observations and Findings

Good Questioning Attitude by Operators

On July 15, 1998, the on-shift operating crew entered Technical Specification (TS) limiting condition for Operation Action Statement 3.6.3.1.1, "Two Primary Containment Hydrogen Recombiners," to allow electricians to perform SVI-M51-T1246, "Hydrogen Recombiner Heater Test," Revision 2, on the "A" HR. The TS specified a 30-day allowed outage time to restore the "A" HR to service. The SVI directed the electricians to obtain resistance-to-ground readings of each HR heater phase within 2 hours after shutting down the HR from a 4-hour surveillance run. The SVI specified an acceptance criterion of 10,000 ohms for each HR heater phase resistance reading and allowed the use of a digital multi-meter to obtain the readings.

While taking the test data, the electricians obtained an initial reading of 3,000 ohms which did not meet the acceptance criterion. However, a reading taken some time later by the electricians read 10,000 ohms which met the surveillance requirement. Even though the final results indicated that the acceptance criterion of the SVI had been met, operations department personnel questioned the validity of the test based on the different readings. Operations department personnel did not declare the "A" HR operable and contacted maintenance department personnel. As a result of discussions between operations and maintenance department personnel, the electricians suspected that megger testing may be the appropriate method for taking this type of resistance reading instead of using a digital multi-meter. Therefore, the electricians took megger readings of the heaters, and the results came back unsatisfactory. Based upon the megger test results and the licensee's position that the megger test was the proper test, the operations department personnel determined that the HRs may never have been appropriately tested. The inspectors determined that the on-shift operating crew demonstrated a good questioning attitude in requesting additional testing on the HR due to the instability of the test results.

Based on the results from the megger test, which were received at 7:15 p.m. on July 15, 1998, the licensee began testing of the HRs as allowed by Surveillance Requirement (SR) 3.0.3. The SR gave the licensee 24 hours to perform the surveillance satisfactorily on the HRs. The inspectors considered that the operators made timely and appropriate TS entries based on their assessment of the test results. On July 16, 1998, the licensee made a notification to the NRC at 2:35 p.m. that the HRs may not have been adequately tested since the initial operation of the plant.

Effective Engineering Involvement in Resolving Testing Methodology for HRs

Engineering personnel, with assistance from the vendor, were promptly and actively involved in the subsequent testing. Engineering personnel contacted other plants with the same type of HRs and determined that the test readings were unstable due to the physical properties of the insulation on the HRs. The insulation material was made of magnesium mono-oxide which had an inverse temperature coefficient effect on the resistance of the HR. The resistance of the HR decreased as the temperature increased during the 4-hour run on the HR. Therefore, sufficient time needed to elapse to allow the HR to cool down for the resistance to increase in order to obtain proper readings. The surveillance stipulated that the readings be taken within 2 hours of shutting down the HR. The licensee conducted the surveillance again on August 28, 1998, which failed due to an attempt to obtain the readings within the 2-hour surveillance time limit. The licensee determined that this time period was not providing an adequate cool down period for the HR which caused the readings to be outside the acceptance criterion of the surveillance.

In addition, engineering department personnel, along with the vendor, investigated the technical basis for obtaining the resistance reading within 2 hours. The licensee determined that the operability of the HR was not contingent on this limit between heatup of the HR and the obtainment of the resistance readings; therefore, the hour limit was not needed in the surveillance. The licensee determined that the 2-hour limit had been incorporated in the Bases section of the licensee's TS when the plant converted to the Improved TS. As a result, the licensee performed a 10 CFR 50.59 applicability check and determined that an unreviewed safety question was not created by the elimination of the 2-hour testing requirement from the Bases of the TS and the surveillance. The inspectors reviewed the licensee's completed 10 CFR 50.59 applicability check and did not have any concerns. Because the licensee, with concurrence from the vendor, determined that the use of the digital multi-meter was an acceptable testing method for the HR, on July 30, 1998, the licensee retracted the previous notification to NRC concerning this event.

c. Conclusion

The inspectors concluded that operators demonstrated a good questioning attitude when assessing the validity of the surveillance data for the HR when initial resistance-to-ground readings did not meet the acceptance criterion of the surveillance test. Also, the on-shift operating crew made the appropriate TS entries based on their assessment of the HR test results. In addition, the inspectors concluded that engineering department personnel were promptly involved in the testing activities and thoroughly pursued the resolution of the proper testing methodology for the HR. The inspectors considered that there was good supervisory and senior management oversight during problem discovery, investigation, and resolution of this issue.

O1.3 Operator Response to Equipment Malfunctions

a. Inspection Scope (71707)

The inspectors observed operators' response to several equipment malfunctions which presented challenges to normal plant operations.

b. Observations and Findings

The inspectors noted that on several occasions during the inspection period equipment malfunctions challenged the operators. The inspectors were conducting observations in the control room prior to the events and directly observed operator actions in response to the challenges. The inspectors noted that the operators responded well during the following three examples:

- On August 20, 1998, the "6B" feedwater heater automatically isolated. An air line to the heater's drain valve leaked, and subsequently failed, causing the isolation of the heater and the addition of colder feedwater to the reactor. The addition of colder feedwater to the reactor could reduce the margin to the thermal limits. The operators promptly identified the problem and immediately took the actions in off-normal Operating Procedure (ONI) N36, "Loss of Feedwater Heating," Revision 3. The operators reduced reactor power to 95 percent and stabilized the feedwater system. The licensee repaired the air line, placed the heater back in service, and returned the plant to full power later in the day.

- On August 20, 1998, operators attempted to perform the normal rotational shifts of the reactor recirculation flow control valve HCU subloops. The operators had the "A1" and "B1" subloops in service. The inspectors observed the operators respond to several equipment problems during the attempted shifts from "A1" to "A2" and "B1" to "B2" subloops. In starting the "A2" and "B2" subloops, the operators determined that the HCU for subloop "A2" leaked and that the low pressure alarm did not clear. The "B2" subloop had abnormal pressure readings and made an unusual noise after starting. The operators stopped both HCU shifts, and returned the "A1" and "B1" subloops to service. The inspectors noted that the operators contacted the system engineer, initiated a work request, and initiated a condition report (CR) to document the problems.

- On August 25, 1998, the inspectors observed instrumentation and control (I&C) technicians perform a post maintenance test (PMT) on the "F" average power range monitor (APRM). The I&C technicians determined that the APRM had failed the PMT because the APRM could not be adjusted to obtain the downscale alarm. The operators and I&C technicians determined that the procedure was not written for this unexpected condition; therefore, the test could not be continued or exited. The inspectors noted that this left the plant in a configuration with a ½ scram initiated from the testing. The operators immediately assessed that keeping the plant in a ½ scram condition was not acceptable. As a result, the operators conferred with maintenance and engineering personnel to determine how to effectively and safely exit the PMT procedure. The licensee temporarily modified the PMT procedure to safely exit the test and reset the ½ scram. Operators directed maintenance department personnel to initiate corrective actions for the "F" APRM.

Operations department personnel demonstrated good command and control while responding to these challenges and took immediate actions to stabilize the plant. Operators effectively interacted with open communications between all levels of the on-shift operating crews. Once the evolutions were completed, operations department personnel developed detailed descriptions of the events and initiated CRs.

c. Conclusions

Operations department personnel took prompt and effective actions in response to the automatic isolation of a feedwater heater, equipment problems associated with shifting reactor recirculation system flow control valve hydraulic control subloops, and the failure of an average power range monitor post-maintenance test. The operators effectively interacted during the events with open communications between all levels of the on-shift operating crews. The operators quickly identified and responded to the situations and initiated corrective action documents in accordance with licensee management expectations.

O1.4 Quality of Operator Briefings and On-Shift Communications

a. Inspection Scope (71707)

The inspectors observed on-shift operating crew communications and attended crew turnovers and briefings.

b. Observations and Findings

The inspectors observed that, while most shift briefings were effective, the quality of the briefings varied from crew to crew. Specifically, the inspectors noted that the some operators were not prepared to discuss watch station status, some speakers used terminology that was not readily understood by all attendees, and some attendees were unable to adequately hear all the speakers. The inspectors considered that these deficiencies decreased the overall quality and effectiveness of the applicable briefings. The inspectors subsequently discussed these observations with the operations manager. The operations manager informed the inspectors that actions have been taken to improve the overall effectiveness of the briefings, such as, having the operations manager and the operations superintendent observe more crew briefings, having attendees perform more peer checking, and training on how to conduct high quality briefings.

On August 6, 1998, the inspectors noted that a miscommunication occurred between the shift technical advisor (STA) and the shift supervisor (SS) concerning authorization of relay replacement work on the reactor core isolation cooling (RCIC) system. The SS expected that the relay work would not start until all the work associated with the EDG had been completed. The STA understood that the EDG work was complete, when it was not, and authorized initiation of the relay work activity. The licensee discovered this error when the SS, STA, and the unit supervisor conducted a plan-of-the-day progress meeting which was attended by the inspectors. The SS directed the STA to terminate the relay replacement work activity. However, workers were only in the walkdown phase of the job. The licensee informed the inspectors that the PRA value had accounted for the concurrent performance of the EDG and RCIC relay replacement work activities. Therefore, there would have been no increased risk to the plant had the I&C technicians started the relay replacement work activity.

c. Conclusions

The inspectors determined that, while most shift turnover briefings were effective, the quality of the briefings varied from crew to crew. For example, at various briefings, some operators were not sufficiently prepared to discuss watch station status, ambiguous terminology was used to discuss equipment status, and some attendees were unable to hear each speaker.

O2 Operational Status of Facilities and Equipment

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

a. Inspection Scope (71707)

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

- emergency diesel generators
- safety-related switchgear rooms
- emergency core cooling systems
- electrical distribution systems

b. Observations and Findings

Equipment operability was acceptable in all cases. However, the inspectors identified an equipment storage problem while touring the plant.

On August 4, 1998, the inspectors noted that two fire extinguishers (FEs) had been stored outside the Unit 1 Division 1 DC switchgear room. The FEs had been properly tagged with an equipment identification (EI) tag which indicated the control method for the temporary storage of the FEs. The inspectors noted that the tag indicated July 31, 1998, as the removal date for the FEs. Therefore, it appeared to the inspectors that the FEs had been stored beyond the storage time limit. As a result, the inspectors contacted the fire protection supervisor (FPS) and informed him of the issue. The inspectors also questioned him on the specific plant condition which warranted the storage and subsequent use of the FEs. The FPS informed the inspectors that the FEs had been placed at that location on April 8, 1998, as a compensatory measure for the impairment of the carbon dioxide fire protection system.

The FPS subsequently informed the inspectors that he had walked down the area, determined that the EI tag had been improperly completed, and initiated actions to request an extension of the FEs. He also informed the inspectors that he had counseled the individuals who incorrectly completed the tag. The inspectors considered that the actions taken by the FPS were appropriate, timely, and effective. However, the FPS did not initiate a condition report (CR) for the problem. The inspectors reviewed Perry Administrative Procedure-PAP-0204, "Housekeeping/Cleanliness Control Program," Revision 10. Section 6.4 of PAP 0204 specified the maximum temporary storage of materials using an EI tag was 3 months, and that approval was needed by the responsible superintendent for storage greater than this period.

On August 10, 1998, the inspectors discussed the decision of the FPS to not generate a CR with the compliance engineer. The compliance engineer indicated that a CR should have been initiated and the FPS subsequently generated a CR on August 17, 1998.

These activities did not involve safety-related activities; therefore, the deficiencies noted during the review of these activities do not constitute violations of NRC requirements.

c. Conclusions

The inspectors concluded that the FPS implemented effective corrective actions for two fire extinguishers which had been temporarily stored beyond the guidance allowed in the station's housekeeping procedure. However, a condition report was not initiated for this issue until the inspectors identified that licensee management's expectations were not met regarding entering this information into the corrective action program.

O8 Miscellaneous Operations Issues (92901)

O8.1 (Closed) Inspection Followup Item 50-440/96002-02: The licensee identified concerns with using the polar crane to lift tools and staging equipment over the reactor cavity. The licensee was concerned that the crane was not single failure proof. The licensee halted use of the crane over the reactor cavity until a safety evaluation was completed. The licensee concluded, based on the evaluation, that an unreviewed safety question did not exist and that the use of the crane to lift staging equipment was within the lift rating of the crane. The inspectors reviewed the evaluation and had no concerns. This item is closed.

O8.2 (Closed) Unresolved Item 50-440/96002-04: The licensee identified that TS did not allow for opening the primary containment personnel air lock while the reactor was critical. An evaluation was performed that demonstrated that minimal safety risk and consequences existed with the door open briefly to allow entry and exit through containment. The licensee submitted a TS amendment which was approved to allow briefly opening the personnel air lock for containment entry and exit. This item is closed.

O8.3 (Closed) Inspection Followup Item 50-440/96002-07: The inspectors identified that the licensee's operating shift crews were not established as described in the Updated Final Safety Analysis Report (UFSAR). Section 13.1.2.3 of the UFSAR described the existence of five operating shift crews during normal activities and a minimum of four crews may be established during certain activities such as startup testing or extended outages. The inspectors noted during the 1996 refueling outage, that only three operating shift crews were established. The licensee revised the UFSAR to allow more flexibility and to reflect their current practices. This item is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62707, 61726)

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

- Surveillance Instruction SVI-M14-T9314, "Type C Local Leak Rate Test of 1M14 Penetration V314," Revision 7
- SVI-M14-T9313, "Type C Local Leak Rate Test of 1M14 Penetration V313," Revision 7
- SVI-C51-T0027F, "APRM [average power range monitor] F Channel Functional for 1C51-K-605F," Revision 6
- SVI-R43-T1317, "Diesel Generator Start and Load Division 3," Revision 8
- SVI-C71-T0051, "Reactor Protection System Manual Scram Channel Functions," Revision 2
- SVI-E51-T1294-A, "RCIC actuation - Suppression Pool Water Level - High Channel A Functional for 1E51-N636A," Revision 2

The inspectors observed good use of three leg communications during activities. Also, the inspectors determined that there was good interface with the on-shift operating crew during these activities. The inspectors did not identify any concerns with the performance of these activities.

M1.2 Division II Planned Maintenance Outage

a. Inspection Scope (62707)

The inspectors reviewed the licensee's planning and performance of extensive maintenance on Division II equipment during the week of July 27, 1998.

b. Observations and Findings

The licensee planned most of the outage work activities to be on the emergency service water (ESW) system, the emergency diesel generator (EDG), and the associated support systems. The licensee considered that the 72-hour limiting condition for operation (LCO) allowed outage time for the EDG was the most limiting LCO for all the planned maintenance activities. The licensee initiated additional administrative controls and management oversight for the outage because the planned work accounted for 86 percent of the LCO allowed outage time, which was over the licensee's administrative limit of 60 percent. The PRA personnel calculated the maximum core damage frequency (CDF) of 3.4E-5 which placed the plant in a medium risk category based on the station's risk program.

The inspectors reviewed the divisional outage schedule and observed that the "B" ESW pump was being replaced. The licensee determined that this work accounted for approximately 31 hours of the total 62 hours planned for all work activities. The inspectors questioned engineering personnel about the need to replace the ESW pump during on-line maintenance. The responsible system engineer explained that maintenance and engineering department personnel had previously gathered and analyzed predictive maintenance data on the "B" ESW pump. The licensee's analysis of the data showed that the pump would probably fail before the start of the April 1999 refueling outage. Engineering and maintenance personnel also determined that an on-line pump rebuild or refurbishment could not be completed within the LCO allowed outage time. Therefore, the licensee made the decision to completely replace the pump.

The inspectors noted several problems with the execution of the divisional outage work. Specifically, the inspectors determined that certain activities were not effectively planned or walked down prior to the performance of the activities. For example, the new shaft coupling device for the ESW pump was of a slightly different design than what was previously installed and what had been ordered for the job. The mechanics had not noticed these differences and therefore encountered difficulties in coupling the pump. Also, the mechanical maintenance personnel did not observe the expected tolerances when coupling the pump, which required unanticipated machining. The licensee determined that this additional work added approximately 10 hours to the original 62-hour outage schedule. These and other planning problems could have resulted in the licensee exceeding the allowed LCO time for this outage. However, the licensee initiated efforts that were effective in allowing the work to be completed in approximately 93 percent of the LCO allowed outage time.

c. Conclusions

The inspectors concluded that the licensee was proactive in replacing a degraded emergency service water pump prior to its failure. While the outage was completed within the allotted time in the applicable TS LCO, better planning for the outage could have resolved pump shaft design differences and could have reduced the on-line out-of-service time of safety-related equipment.

M1.3 Probabilistic Risk Assessment Activities

a. Inspection Scope (62707)

The inspectors reviewed the licensee's use of PRA. The inspectors reviewed the licensee's on-line risk assessment methods, determined how risk was addressed by operators, and interviewed operators and PRA personnel.

b. Observations and Findings

In the review of the licensee's PRA program, the inspectors determined that the licensee had effective PRA techniques and methods in place. The inspectors also determined that the licensee would soon implement a more comprehensive system through an on-line risk monitoring system, and provide specific PRA training for operators.

The inspectors reviewed the administrative procedures for risk assessment activities and determined that the licensee categorized plant risk in four levels: 1 (very high risk), 2 (high risk), 3 (medium risk), and 4 (low risk). The PRA personnel reviewed the weekly activity schedules to determine the risk significance of planned activities. As a result of this review, PRA personnel communicated daily risk categories in the plan-of-the-day meeting and in the daily plant schedule. Also, the licensee published the top four systems to maintain in an operable status and provided information on systems or components that became important to risk as the plant's configuration changed. The inspectors determined that the licensee effectively controlled activities to maintain the plant in a low or medium risk category when performing scheduled maintenance activities.

Operators contacted PRA personnel for updated risk values when emergent work or equipment failures were encountered. The inspectors monitored the operators' response to the inoperability of the "A" ESW outlet isolation valve from the residual heat removal heat exchanger (1P45F068A). The ESW system engineer informed the shift supervisor (SS) that the valve may not open because the valve operator had missing gear teeth. The SS contacted the PRA analyst and requested a new risk value with this component out of service. The licensee had determined that the plant was in the low risk category before the discovery of this problem.

The PRA analyst informed the SS that the new PRA value was calculated at approximately 6.7E-6/rx-yr which corresponded to a low risk category. However, the inspectors and operations management determined that this value could not be correct because the loss of this valve adversely impacted plant operations. Again, the SS communicated with the PRA analyst to discuss the basis for the initial PRA value, which was discovered to be based on the inability to stroke the valve closed. The SS clarified that he wanted a PRA value based upon the valve failing closed, causing a loss of ESW to the heat exchanger. The PRA analyst calculated a new risk value of approximately 3.4E-5/rx-yr, which placed the plant in a medium risk category.

On August 25, 1998, the inspectors observed the initial training session for operations department personnel on the new on-line risk monitoring system. The PRA personnel stated during the training that details had not been fully developed on how the on-shift operating crew would use the risk data. The inspectors determined that a benefit to the operators was the ability to get on-line values and perform "what if" calculations.

c. Conclusions

The inspectors determined that the licensee effectively incorporated PRA techniques into daily plant operations. For example, an SS requested a new PRA value for the potential loss of an emergency service water isolation valve after it was discovered that the valve may not open due to missing gear teeth. The SS questioned the initial PRA value that was provided and a recalculation of the value resulted in the identification that the risk category was actually medium as opposed to low for this condition.

M8 Miscellaneous Maintenance Issues (92902)

M8.1 (Closed) Unresolved Item 50-440/96005-08: UFSAR Section 15A.5.3, "Repair Time Rule," contained the bases for selecting surveillance testing frequencies and durations. The section also contained requirements for maintaining the validity of the assumptions used to decide frequencies. The licensee identified that on-line maintenance, as a practice, was not included in the bases and as such, did not maintain the validity of the assumptions. The licensee initiated an evaluation via the station's deficiency report program. The licensee concluded that the practice of performing on-line maintenance was acceptable and did not adversely affect UFSAR Section 15A.5.3. The inspectors reviewed the evaluation and concluded that the licensee adequately addressed the issue. This item is closed.

M8.2 (Closed) Violation 50-440/96006-02: Measuring and test equipment (M&TE) and scaffolding was found stored in unauthorized locations. A test instrument was found unattended at the job site near the closed cooling system. The licensee evaluated the consequences associated with an unattended M&TE instrument near the cooling system and determined that the safety significance was minor. The licensee's evaluation also determined that all other test instruments were controlled and accounted for. In addition, PAP-0204, "Housekeeping/Cleanliness Control Program," required that scaffolding, while not in use, to be stored in authorized areas. The procedure was revised to include accountability of individuals using scaffolding and requirements for the scaffolding coordinator to walk down all scaffold areas to ensure proper storage of scaffolding when not in use. The inspector determined that these actions were appropriate. This item is closed.

M8.3 (Closed) Violation 50-440/96018-01: Surveillance Instruction (SVI) B21-T1176, Revision 4, "Reactor Coolant System Heatup and Cooldown Surveillance" was inadequate to ensure compliance to TS. The licensee revised the SVI (Revision 5) to ensure compliance to TS limits, including the limit for a cooldown rate of 100 degrees per hour. This item is closed.

M8.4 (Closed) Unresolved Item 50-440/97009-05: On July 17, 1997, the licensee identified through troubleshooting, that the Division 3 EDG room supply ventilation fan was rotating backwards. This condition prevented the fan from performing its safety support function. The licensee determined that the fan's motor power wiring was reversed, causing the fan to rotate in the reverse direction. The licensee determined that the wiring error occurred on May 12, 1997, during work associated with Repetitive Task R85-3707. Although the wiring termination on the fan motor was documented showing the correct location and was independently verified as correct, the wiring was actually reversed. The licensee verified that during the period that this train of ventilation was inoperable, and the other train was not affected and operable. With one train of ventilation operable, the affected EDG was operable.

The licensee determined that the root cause of the wiring error and failure to detect the error during the independent verification were personnel performance errors. The electrician's failure to properly wire the fan as specified by Repetitive Task R85-3707 was a violation. The licensee provided individual expectations training for the responsible individuals. This corrective action was appropriate based on the licensee's determination that the event was an isolated occurrence. However, the licensee's root cause determination did not address the lack of post-maintenance testing (PMT) requirements associated with repetitive tasks. The licensee subsequently reviewed the PMT process and made the appropriate changes. Because the safety consequences of the wiring error were minor, this failure constitutes a violation of minor significance and is not subject to formal enforcement action. This item is closed.

III. Engineering

E8 Miscellaneous Engineering Issues (92903)

E8.1 Review of Previous Open Items Related to Updated Final Safety Analysis Report (UFSAR) Discrepancies

The inspectors reviewed several open items related to USAR discrepancies. For each item listed below, the resolution completed or scheduled to be completed was considered adequate. Inspection Report 50-440/97008 issued a violation (EA 97-430) of 10 CFR 50.71(e) for inaccurate USAR information. The licensee's response to the violation, dated November 24, 1997, and August 18, 1997, discussed its USAR validation program and stated that the scheduled completion date was October 1998. The following examples of a failure to update the USAR did not have a material impact on safety or licensed activities. Therefore these examples were classified as violations of minor significance that are not subject to formal enforcement action.

- (Closed) Inspection Followup Item 50-440/96003-06: The licensee identified discrepancies with UFSAR Figure 9.3-34, "Main Reheat, Extraction and Miscellaneous Drains" and the system description contained within the UFSAR. Section 9.3.3.2.6 of the UFSAR did not discuss the function or effects of a 3/4 inch drain off the 3-inch condensate drain line to the main condensers from the inboard main steam isolation valves. In addition, a 1995 safety evaluation applicability check did not identify that the line was not shown on the UFSAR figure.

  The licensee recognized the error shortly after the safety evaluation applicability check was completed and initiated an investigation. The applicability check was performed with activities to block permanently (retire-in-place) the 3/4 inch line due to excessive leakage from an isolation valve in the line and to initiate a drawing change. Subsequently, the licensee decided not to retire the 3/4 inch line in-place, but to repair the isolation valve. The licensee canceled the drawing change. However, engineering department personnel did not recognize that the 3/4 inch line was contained on the UFSAR figure and was not contained in the system description. The licensee identified this error and corrected Section 9.3.3.2.6 of the UFSAR. This item is closed.

- (Closed) Inspection Followup Item 50-440/96003-09: The licensee identified discrepancies with UFSAR Section 9A.7, "Deviations to Appendix R." This section discussed the exceptions the licensee took to the requirements of 10 CFR Part 50, Appendix R, "Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979." The NRC documented the review of the exceptions in Supplement No. 7 to the safety evaluation report. On November 14, 1995, during Audit 95-18, licensee quality assurance department personnel determined that Engineering Calculation P54-24, "Fire Load Calculations," had not been kept current. This was documented in problem identification form (PIF) 95-2322. During the investigation of PIF 95-2322, the licensee concluded, in a memorandum dated January 3, 1996, that safe shutdown capability had been maintained even though 31 of 56 fire zones did not conform with the UFSAR. The memorandum also identified the following additional fire protection issues: three fire zones had unapproved combustible material; a wall needed its fire rating verified; and, changes to a fire barrier made it different from the description in the UFSAR. On February 20, 1996, licensee personnel identified unauthorized combustible material in Fire Zone 1AB-1g which was documented in PIF 96-839. Fire Zone 1AB-1g was described in the UFSAR as including an area of separation between pressure transmitters. The UFSAR stated that, "Because of low fuel load and lack of intervening combustibles, it is unlikely that a fire would disable redundant transmitters." The transmitters, located at the 574' elevation of the auxiliary building, were separated by approximately 35 feet. The licensee observed six plastic tool cases and some plastic bags in a tool cage within the combustible-free area. The inspectors verified that the combustible materials had been removed and observed that a permanent metal sign had been posted classifying the cage as a "Combustible-free Area." This item is closed.

- (Closed) Unresolved Item (URI) 50-440/96005-05: Battery Rooms Not Locked as Described in USAR Section 8.3.2.1.2.1. The inspectors identified that the doors to the battery rooms did have a latch mechanism; however, no key was required to access the room. This did not appear to meet the USAR statement that the doors were "locked." This item was under review as a deficiency in the licensee's USAR Validation Project. This item is closed.

- (Closed) Unresolved Item 50-440/96006-03: The licensee identified that the UFSAR Figure 9.2-13, "Condensate Transfer and Storage System," was not according to Plant Drawing 302-102. Drawing 302-102 was changed in June 1993 without changing the UFSAR figure. The licensee completed a safety analysis and found that the drawing change did not represent an unreviewed safety question. The inspector independently reviewed the evaluation and agreed with the licensee's conclusion. The licensee updated the UFSAR figure to reflect the as-built condition. The inspector reviewed the current revision of Figure 9.2-13, Revision 9, dated April 1998, and concluded that the figure was maintained consistent with the actual as-built conditions. This item is closed.

- (Closed) Unresolved Item 50-440/96006-05: The licensee identified that the UFSAR Section 17.2.1.3.5.1, "Company Nuclear Review Board (CNRB)" did not reflect actual functions and practices of the CNRB. The licensee revised the UFSAR, Revision 8, dated October 1996, to reflect the actual functions of the CNRB. The inspectors reviewed the revised UFSAR and concluded that the licensee properly addressed this problem. This item is closed.

E8.2 (Closed) Inspection Followup Item 50-440/96003-13: The licensee identified discrepancies with UFSAR Section 15, Appendix 15B "Reload Safety Analysis." This appendix included information on changes in reactor core design and how they affect the core design as described in the main text of the UFSAR. Most of the information in this appendix was provided by the fuel manufacturer, General Electric (GE). During the inspection period, GE notified the licensee of four errors or problems that affected the analyses used to develop the appendix. On March 12, 1996, GE notified the licensee that some fuel pellets in the reload fuel may be less dense than specified (PIF 96-1389). On March 13, GE notified the licensee of an error in the emergency core cooling system analysis caused by their failure to consider flow through the reactor bottom head drain (PIF 96-1422). The licensee's initial evaluation of these two conditions determined that they would have minor impact on fuel rod peak center line temperature during bounding transients.

On March 28, 1996, GE notified the licensee of four errors in various computer programs used for core and fuel bundle design. The licensee's initial evaluation of these errors indicated that they would have no impact at Perry. On April 3, 1996, GE notified the licensee that there was an error in GE's methodology for calculating the minimum critical power ratio (MCPR) safety limit. Since the error was not conservative, the licensee provided instructions to the operators to limit the indicated maximum fraction of limiting critical power ratio (MFLCPR) to .985 instead of 1. The operators used the MFLCPR as the operating limit to ensure compliance with the MCPR safety limit. After GE discussed the issue with the NRC at NRC headquarters on April 17, 1996, the licensee reduced the MFLCPR limit to .98. The inspectors verified that MFLCPR was consistently below the new limit at about .85.

The licensee evaluated each situation to determine if an safety evaluation was required. The inspectors concluded that appropriate safety evaluations were prepared after the problems were identified. This item is closed.

E8.3 (Closed) Inspection Followup Item 50-440/96004-01: On April 23, 1996, a small fire occurred in the control room because of a short in a valve position matrix light. Shorting of matrix lamp sockets was a recurring problem. The licensee's root cause determination found that a combination of purchasing lamps of poor quality from different manufactures and the lack of an insulating device to protect against shorts caused most of the failures. The licensee determined that some lamps supplied with insulating devices had either internal insulating sleeves or external resistors, while some had both or none. The licensee removed all lamps from within the plant and stores that did not have both devices. The licensee also modified the sockets to include an external resistor for additional protection from shorts. The inspector determined that the licensee's corrective actions were appropriate. This item is closed.

E8.4 (Closed) Unresolved Item 50-440/96017-07: The inspectors were concerned that Field Clarification Request (FCR) 016809 was used to do general checks of the high pressure core spray system pump's electrical breakers and that the design change process was bypassed. The inspectors identified that the FCR did not include documented basis for the conclusion that the breaker was acceptable and the extent of the condition (i.e., what other breakers had similar problems) was not addressed. The licensee conducted a safety evaluation and evaluated the use of FCRs in general. The licensee determined that FCR usage had bypassed the design change process; however, no cases were identified where an unreviewed safety question existed. The licensee implemented corrective actions to delete the FCR process from Administrative Procedure PAP-0309, "Processing Plant Modifications." The inspectors reviewed the licensee's corrective action and determined that the action was acceptable. This item is closed.

E8.5 (Closed) Unresolved Item 50-440/97009-06: On July 21, 1997, the licensee found that Fuse R42-F0303, supply power to the switchyard backup relay for the S-10-PY-bus section between Breakers S-620 and S-622, was not installed. This power feed to Bus S-10-PY-bus was from the abandoned Unit 2. This fuse affected the backup protection relaying for the switchyard. The primary protection relays were unaffected. Evaluations from the licensee determined that, although risk increased with the potential loss of the backup protection, the station had always operated within their design basis. The licensee's analysis adequately demonstrated that the single failure criterion was met and maintained. Based upon this analysis, the inspector concluded that this condition was not in violation of the licensee's TS or license bases. This item is closed.

E8.6 (Closed) Unresolved Item 50-440/97016-05): Unexpected RCIC turbine trips. The RCIC turbine tripped on overspeed on two attempted restarts at the end of refueling outage 6 in October 1997. In August 1997, the licensee replaced a nitride stem with an inconel stem to reduce stem binding from corrosion. The licensee initiated this action to correct a long-term industry problem with RCIC governor valve stem binding. Engineering department personnel developed the design, in conjunction with the stem machining vendor. Engineering department personnel attempted to design a stem that was equivalent to the original equipment manufacturer's (OEM) stem made by Dresser-Rand. After the failure, the licensee conducted a root cause analysis and determined the following four apparent root causes of the failure: 1) the RCIC govenor valve stem was 1mil larger than OEM specifications with a minor machining (high spot) defect; 2) the carbon spacers used for the stem had undersized interior dimensions (ID); 3) engineering department personnel failed to adequately identify clearances between the stem and spacers; and 4) engineering department personnel failed to thoroughly evaluate equivalencies between the two stem materials, including thermal growth differences.

The inspectors determined that the licensee completed a comprehensive root cause analysis. The licensee's corrective actions included process improvements to more closely monitor tolerances and installation of the spacers on the stem. The licensee made subsequent RCIC repairs and conducted testing with no further problems. The licensee also worked closely with the OEM to produce a 10 CFR Part 21 notification so that the industry could gain from their experience. This failure to identify and correct equivalency differences between the OEM and vendor stems, and the clearances associated with the carbon spacers, is considered a violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control." This non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. **(NCV 50-440/98016-01(DRP))**

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 Actions by Operations Superintendent to Enhance Radiological Practices

a. Inspection Scope (71750)

The inspectors observed a non-licensed operator perform a venting activity of a control rod drive hydraulic control unit (HCU) in response to a control room alarm.

b. Observations and Findings

On July 12, 1998, the inspectors observed a non-licensed operator vent one of the control rod drive HCUs. The PPO did not wear any gloves and he allowed the water-mist from the HCU to vent to containment atmosphere and onto a rubber mat that he used to perform the activity. The inspectors questioned the PPO as to whether the fluid in the system was contaminated and if he needed to wear gloves. The PPO informed the inspectors that gloves were not warranted as the water was not contaminated. The inspectors further reviewed this practice and determined that the operations superintendent (OS) had observed and questioned this same practice several weeks ago when he accompanied a PPO on rounds.

The OS questioned the PPO, who responded that no contaminations had resulted from the previous use of this practice. The OS requested that each crew be canvassed to determine the practice used when conducting this activity, and requested that a radiation protection technician sample the fluid. Also, the OS conducted a historical review of the practice and concluded that no contaminations had occurred. Therefore, the OS allowed the PPOs to continue this practice. The inspectors considered that this decision was acceptable.

The licensee made several attempts to obtain and analyze a sample of the HCU fluid but was not successful. The licensee was able to obtain an adequate sample on July 22, 1998, and tested the sample which indicated traces of cobalt-60. The licensee determined the amount of activity was below the procedural guidance for contamination classification. The licensee subsequently conducted a survey of the tool box, which contained equipment used by the PPOs in performing the HCU venting activities, and did not find any contaminated equipment.

On July 24, 1998, the OS issued a memo which instituted an enhanced radiological practice for the PPOs to wear protective clothing when conducting this and other activities that breached the HCUs. This decision was based upon low levels of cobalt-60 found in the HCU fluid.

c. <u>Conclusion</u>

The inspectors determined that the operations superintendent appropriately questioned an operator's radiological practices when manipulating equipment and interfacing with fluid in a potentially contaminated system during control rod drive hydraulic control unit (HCU) venting activities. The licensee initiated timely actions in analyzing the activity level of the HCU fluid which was below that which required protective clothing. The inspectors concluded that the operations superintendent took proactive actions by instituting an enhanced radiation protection practice requiring operators to wear protective gloves when conducting these and similar activities that breached the HCUs.

<u>V. Management Meetings</u>

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on September 8, 1998. 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 September 1, 1998, the licensee met with Region III management to discuss their commitment and adherence to the station's business plan for facilitating continuous improvement in equipment reliability and human performance. The licensee's business plan had the following four critical success areas: 1) Safety; 2) People; 3) Reliability; and 4) Cost. Each area had specific performance measures to monitor the station's progress in meeting the business plan. The licensee also discussed plant equipment challenges with leaking feedwater check valves and butterfly valves, a long-standing deficiency with control room lamp indications, and scram reduction efforts associated with removing vulnerabilities from the electrohydraulic control system. The licensee planned to correct these problems during the upcoming 35-day refueling outage which was scheduled for April 10, 1999, through May 15, 1999. The licensee presented the goals for Refuel Outage 7, and informed regional management of several station initiatives such as the planned power upgrade, a new on-line risk management system, and a change from the current 18-month to a 24-month operating cycle.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

L. Myers, Vice President, Nuclear
H. Bergendahl, Director, Nuclear Services Department
N. Bonner, Director, Nuclear Maintenance Department
W. Kanda, General Manager, Nuclear Power Plant Department
F. Kearney, Superintendent, Plant Operations
T. Rausch, Operations Manager
R. Schrauder, Director, Nuclear Engineering Department
J. Sears, Radiation Protection Manager

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 61726:	Surveillance Observation
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71750:	Plant Support
IP 92901:	Followup - Operations
IP 92902:	Followup - Engineering
IP 92903:	Followup - Maintenance

ITEMS OPENED AND CLOSED

Opened

50-440/98016-01	NCV	Inadequate design control of RCIC stem

Closed

50-440/96002-02	IFI	Use of polar crane in containment
50-440/96002-04	URI	UFSAR Item, structural steel frames and floors
50-440/96002-07	IFI	UFSAR Section 13.1.2.3, operating shift crew
50-440/96003-06	IFI	UFSAR Figure 9.3-34, main reheat extraction and misc. drains
50-440/96003-09	IFI	UFSAR Section 9A.7, deviation to Appendix R
50-440/96003-13	IFI	UFSAR Section 15, Appendix 15B Reload Safety Analysis
50-440/96004-01	IFI	Review/procurement and engineering issues
50-440/96005-08	URI	UFSAR Section 15A.5.3, repair time rule
50-440/96005-05	URI	Battery Room Not Locked
50-440/96006-02	NOV	M&TE and scaffolding control
50-440/96006-03	URI	UFSAR Figure 9.2-13, drawing change
50-440/96006-05	URI	UFSAR Section 17.2.1.3.5.1, CNRB delegation and function
50-440/96017-07	URI	Improper use of FCR
50-440/96018-01	VIO	Inadequate procedure to determine cooldown rate

50-440/97009-05	URI	EDG fan inoperable
50-440/97009-06	URI	Poor response to missing fuse
50-440/98016-01	NCV	Inadequate design control of RCIC stem

LIST OF ACRONYMS USED

APRM	Average Power Range Monitor
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
CNRB	Company Nuclear Review Board
CR	Condition Report
CRD	Control Rod Drive
DRP	Division of Reactor Projects
EA	Enforcement Action
EDG	Emergency Diesel Generators
EI	Equipment Identification
ESW	Emergency Service Water
EHC	Electro Hydraulic Control
FCR	Field Clarification Request
FE	Fire Extinguisher
FPS	Fire Protection Supervisor
GE	General Electric
HCU	Hydraulic Control Unit
HPCS	High Pressure Core Spray
HR	Hydrogen Recombiner
HVAC	Heating, Ventilation, and Air Conditioning
I&C	Instrumentation and Controls
IFI	Inspection Followup Item
IP	Inspection Procedure
IR	Inspection Report
LCO	Limiting Condition for Operation
MCPR	Minimum Critical Power Ratio
MFLCPR	Minimum Fraction of Limit Critical Power Ratio
M&TE	Measuring and Test Equipment
NCV	Non-cited Violation
NRC	Nuclear Regulatory Commission
OEM	Original Equipment Manufacturer
ONI	Off Normal Instruction
OS	Operations Superintendent
PACP	Plant Access Control Point
PAP	Plant Administrative Procedure
PDR	Public Document Room
PIF	Problem Identification Form
PMT	Post Maintenance Testing
POD	Plan-of-the-Day
PPO	Perry Plant Operators
PRA	Probabilistic Risk Assessment
RCIC	Reactor Core Isolation Cooling
RG	Regulatory Guide

RHR	Residual Heat Removal
SOI	System Operating Instruction
SR	Surveillance Requirements
SS	Shift Supervisor
STA	Shift Technical Advisor
SVI	Surveillance Instruction
TS	Technical Specification
US	Unit Supervisor
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
VIO	Violation