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U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Nos. 50-315/91004(DRP), 50-316/91004(DRP)

Docket Nos. 50-315, 50-316 License Nos. DPR-58, DPR-74

Licensee: American Electric Power Service Corporation
Indiana Michigan Power Company
1 Riverside Plaza
Columbus, OH 43216

Facility Name: Donald C. Cook Nuclear Power Plant, Units 1 and 2

Inspection At: Donald C. Cook Site, Bridgman, MI

Inspection Conducted: February 6, - March 19, 1991

Inspectors: H. B. Clayton B. L. Jorgensen

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Approved By: B. L. Jorgensen, Chief
Projects Section 2A

Date

Inspection Summary

Inspection from February 6 through March 19, 1991
Reports No. 50-315/91004(DRP), 50-316/91004(DRP))
Areas Inspected: Routine unannounced inspection by the resident inspectors of actions on previously identified items, operational safety verification, reactor trip, maintenance, surveillance, simulator procedure evaluation, engineering and technical support, security, and safety assessment/quality verification. No Safety Issues Management System (SIMS) items were closed.

Results: No violations or deviations were identified in any portion of the 9 areas inspected. The inspection identified strengths in the plant operations area. The response of the plant engineers, to potentially safety significant issues, was considered mixed, as described in the area of engineering and technical support. There were no notable weaknesses identified in any of the areas reviewed. One unresolved item was identified relating to the blocked Unit 1 emergency boration flowpath (see paragraph 8.b).

Plant Operations:

During this reporting period, Unit 1 operated at full power with no major operational problems. Additionally, the inspector noted that operations department concerns for the operability of the emergency boration flowpath initiated the investigation into and the corrective action for the cause

of the blocked flow path. The inspector considers the actions taken by the operations department to bring this issue up for resolution by the Problem Assessment Group as a strength.

Likewise, Unit 2 experienced no major operational problems during this reporting period. The March 13, 1991, reactor trip was caused by an offsite electrical disturbance rather than a malfunction of onsite equipment or system. The inspector noted the response to the Unit 2 reactor trip by the operators as a strength.

Maintenance and Surveillance:

The surveillance and maintenance activities were performed satisfactorily during this reporting period with no major strengths or weaknesses identified.

Engineering and Technical Support:

The licensee's timely response to effective safety system problem resolution was mixed. In one instance, a very conservative and aggressive investigation was conducted to determine the cause(s) for the turbine driven auxiliary feedwater (TDAFW) pump trip after the Unit 2 reactor trip on March 13, 1991. In another instance, there appeared to be a lack of proactive and aggressive actions taken to prevent recurrence of a blocked Unit 1 emergency boration line while the root cause(s) were being investigated. The investigation into the cause of the TDAFW pump trip was especially notable. Despite the auxiliary feedwater (AFW) system engineer being away for training, the plant system engineering group effectively redirected its resources for the investigation.

DETAILS

1. Persons Contacted

* * A. Blind, Plant Manager
* * J. Rutkowski, Assistant Plant Manager - Technical Support
* * L. Gibson, Assistant Plant Manager - Projects
* * K. Baker, Assistant Plant Manager - Production
* B. Svensson, Executive Staff Assistant
* J. Sampson, Operations Superintendent
* * P. Carteaux, Safety and Assessment Superintendent
* T. Beilman, Maintenance Superintendent
* J. Droste, Technical Superintendent- Engineering
* * T. Postlewait, Design Changes Superintendent
* L. Matthias, Administrative Superintendent
* * J. Wojcik, Technical Superintendent - Physical Sciences
* M. Horvath, Quality Assurance Supervisor
* D. Loope, Radiation Protection Supervisor

The inspector also contacted a number of other licensee and contract employees and informally interviewed operations, maintenance, and technical personnel.

*Denotes some of the personnel attending the Management Interview on March 21, 1991.

2. Actions on Previously Identified Items (92701, 92702)

From January 30 through February 7, 1991, the Nuclear Regulatory Commission (NRC) administered requalification examinations to D.C.Cook Nuclear Plant employees. A complete examination summary is contained in NRC Inspection Report No. 50-315/OL-91-01. To summarize that report, the examination consisted of written and operating requalification tests administered to ten reactor operators (RO) and ten senior reactor operators (SRO). One SRO failed the simulator portion of the examination. Another SRO and one RO failed the Job Performance Measure portion of the examination. A third SRO failed the written examination. One SRO mentioned above failed his second retake examination. All other operators and all crews passed the examination. The licensee's requalification program was declared satisfactory in accordance with the program performance criteria in NUREG-1021, ES-601.

No violations, deviations, unresolved or open items were identified.

3. Operational Safety Verification (71707, 71710, 42700)

Routine facility operating activities were observed as conducted in the plant and from the main control rooms. Plant startup, steady power operation, plant shutdown, and system(s) lineup and operation were observed as applicable.

The performance of licensed ROs and SROs, of Shift Technical Advisors, and of auxiliary equipment operators was observed and evaluated including procedure use and adherence, records and logs, communications, and the degree of professionalism of control room activities. The Plant Manager, Assistant Plant Manager-Production, and the Operations Superintendent were well-informed on the overall status of the plant, made frequent visits to the control rooms, and regularly toured the plant.

Observations of the control room monitors, indicators, and recorders were made to verify the operability of emergency systems, radiation monitoring systems and nuclear reactor protection systems, as applicable.

a. Unit 1 operated this reporting period at essentially 100 percent power. With the exception of the blocked emergency boration flowpath, Unit 1 experienced no major operational problems and at the end of the reporting period was operating at 100 percent power.

b. Unit 2 began this reporting period at 100 percent power. The unit commenced a power decrease to 59 percent power for main feedwater pump turbine condenser cleaning on February 16, 1991. Power was restored to 100 percent on February 21, 1991. A forced power reduction to 70 percent occurred on February 22, 1991. This was caused by the negative reactivity effect of xenon buildup following the power increase to 100 percent on the previous day. The licensee was unable to compensate for the xenon buildup because all dilution flowpaths were removed from service to repair a leaking primary water (PW) valve. The leaking PW valve had caused temperatures in the emergency boration piping to decrease below the Technical Specification (T.S.) requirements. Plant management decided to allow the power decrease during the repair of the PW valves. The unit achieved 100 percent power again on February 23, 1991, following completion of the maintenance work. The unit tripped on March 13, 1991, due to offsite electrical disturbances (see paragraph 4). Following the reactor trip investigation, the unit achieved 100 percent power on March 18, 1991, and continued operating at full power through the end of the inspection period. The inspector noted operator action following the trip as a particular strength. There were no other significant operational problems.

c. On February 8, 1991 the inspector accompanied the NRC Region III Section Chief for the D. C. Cook plant on a general tour of the Auxiliary Building and Turbine Building areas. Housekeeping appeared generally satisfactory and material condition had improved somewhat since the units returned to power following the recent back-to-back refueling outages. Minor discrepancies noted on the tour were given to appropriate plant supervisors for follow-up action. One discrepancy of note was a leak of approximately one drop per minute at the Unit 1 Letdown Heat Exchanger head. The leak was contained by a catch basin that was fed to an equipment drain a few feet away. No job order tag was attached to the equipment. The inspector checked the status of these items and found a job order to be active. The work to replace the head gaskets to fix the problem had been put on hold due to the small magnitude of the leak and the potential for

personnel exposure (the tube bundle would have to be removed). Meanwhile, the licensee has continued to monitor the leak and is prepared to replace the head gasket should the leak rate accelerate.

No violations, deviations, unresolved or open items were identified.

4. Reactor Trip (93702)

On March 13, 1991, at about 6:51 a.m. (EST), Unit 2 reactor tripped as a result of a turbine trip from 100 percent power. At the time of the trip, operators noted drastic load swings on the Unit 2 main generator electrical output meter. Operators reported observing load swings from 1100 megawatts (MWE) (approximate generator output at 100 percent reactor power) to 0 MWE. The load swings were believed to have been caused by offsite electrical disturbances caused by a major winter storm in the area. Just prior to the trip, a 765 KV line, located north of Indianapolis was lost when several transmission towers collapsed due to ice buildup. Loss of 345 KV lines also occurred and affected Unit 1 stability for a time, but not severely enough to cause a Unit trip. Post trip review found that the turbine trip was caused by high moisture separator reheater water level. All systems except the turbine-driven auxiliary feedwater (TDAFW) pump functioned as expected. Initially, a main steam stop valve, 2-MRV-230, was considered to have functioned abnormally. It had come off its open detent and had drifted fully closed. Post trip investigation indicated, based on past experience, that under these conditions the main steam stop valve would come off its open detent. The licensee concluded that no abnormal operation had occurred. Additionally, it was noted that the steam pressure in the main steam piping associated with 2-MRV-230 was higher than that of the other three steam generators. The licensee believed that this higher steam pressure was the cause for 2-MRV-230 closing first. There were two other main steam stops which had also come off their open detents. The operators noticed this and repositioned the valves to their full open position before they drifted their closed position. The discussion regarding the licensee's investigation of the TDAFW pump is discussed in section 8 of this report. Following the licensee's investigation, the unit was successfully returned to service and reached 100 percent power on March 18, 1991.

No violations, deviations, unresolved or open items were identified.

5. Maintenance (62703, 42700)

Both corrective and preventive maintenance activities in the mechanical, electrical, and instrument and control areas were routinely inspected. The focus of the inspection was to ensure the maintenance activities reviewed were conducted in accordance with approved procedures, regulatory guides, industry codes or standards, and in conformance with Technical Specifications. The following items were considered during this review: the Limiting Conditions for Operation were met while components or systems were removed from service, approvals were obtained prior to initiating the work, activities were accomplished using approved procedures, post maintenance testing was performed as applicable, quality control records were maintained, activities were accomplished by qualified personnel, radiological controls were implemented, and fire prevention controls were implemented.

The following activities were inspected:

a. The inspector observed the repair work and reviewed the documentation associated with Job Order A53137. This was issued to repair two components identified as a source of boric acid leakage. These leaks were believed to be the primary cause for the excessive boric acid heat trace alarms. One of the components was 1-QFC-411 (electric flow transmitter) and the other was 1-CS-487 (inlet shutoff diaphragm valve to 1-QFC-411). Observation of the work activity and associated document review identified no major discrepancies. The procedure was concise and well-written, and was followed properly. Quality control inspection "hold points" were properly observed and documented. The inspector also noted that the valve reassembly was performed satisfactorily.

However, the inspector noted delays encountered during this leak repair which impacted the completion of the maintenance activity. These delays were caused by -

- Less than optimum work coordination and communication of maintenance activities between the operations and the maintenance departments;
- Lack of foresight by the maintenance department for things that could potentially hinder the repair process; and,
- Lack of readily available qualified spare parts.

The delays resulted in a brief period when the normal boration flowpath could not be returned to a fully "operable" status.

Additionally, the inspector noted that a pure water leak in the Unit 2 boric acid system had caused a forced power reduction of Unit 2 on February 22, 1991. The licensee found that a leaking primary water valve (PW-265) was causing low temperature alarms in the heat trace circuits. Because the low temperature condition placed Unit 2 in a 72-hour Limiting Condition for Operation, the licensee decided to repair PW-265. In order to work on PW-265, it was necessary to remove all dilution flowpaths for Unit 2 from service. However, the removal of the dilution flowpaths removed the ability to offset xenon buildup following a return to 100 percent power from a previous planned maintenance activity. This caused a brief forced power reduction on February 22, 1991. Unit 2 returned to 100 percent power on the following day.

Examples of parts problem noted by the inspector involved the replacement of 5/16 inch body-to-bonnet studs which showed some thread erosion. The maintenance supervisor directed that all four of the studs be replaced. However, no spare replacement studs were found in the plant stock and workers had to scavenge the parts from a spare valve in the storeroom. A second example involved the replacement of the diaphragm on valve 1-CS-487 performed in accordance with **12 MHP 5021.001.023, "Disassembly, Repair, and Reassembly of Grinnel Air-Operated and Handwheel-Operated Diaphragm Valves." The maintenance personnel discovered that when QFC-411 was disconnected, some teflon tape from inside the instrument had worked its way out of the flanged opening. The maintenance workers questioned whether this "as-found" configuration was acceptable and whether replacement of the gaskets alone would repair the leak. Initially, the workers were instructed, by a phone call from the I&C supervisor, to replace the gaskets and to reinstall the instrument "as-is." Concern, by the maintenance personnel, that just replacing the gaskets would not stop the leak resulted in a request to the I&C supervisor to review the as-found maintenance condition. After reviewing the as-found condition for QFC-411, the I&C supervisor agreed with the maintenance personnel and decided that the replacement of the instrument was warranted. However, no nuclear-grade replacement flow instrument was available, so the licensee had to "dedicate" a spare non-nuclear grade instrument from the storeroom.

The inspector reviewed the dedication plan and the plan appeared to encompass all critical characteristics of the "old" flow instrument. No problems were noted during this review. The inspector also noted that post-maintenance testing of the components was conducted satisfactorily and no leakage was observed. The flowpaths were returned to service within the time required by the Technical Specifications.

b. The inspector reviewed Job Order A003197 on 1-CS-536, Unit 1 Chemical Volume and Control System (CVCS) discharge cross-tie isolation valve to Unit 2 CVCS discharge header. This was to ensure that the maintenance and post-maintenance tests performed on the valve were adequate following repair of the body-to-bonnet leak. The inspector's review of the job order performed during the outage found that the work had been performed in accordance with an approved procedure (**12 MHP 5021.001.007, "Disassembly, Repair, and Reassembly of Conval Clampseal Valves), and that the proper post-maintenance test criteria had been specified. However, discussion with the licensee maintenance staff, and the inspector's understanding of the nature of the leak and the construction of the valve indicated that the proper post-maintenance test may not have been performed.

The inspector's discussion with the maintenance staff indicated that the valve may have been "cycled dry", implying that hydrostatic pressure may not have been applied to the body-to-bonnet area of the valve during the post-maintenance test. At the end of the inspection period, the inspector had not been able to verify this preliminary conclusion of a possible inadequate post-maintenance test. Although the job order specified the test criteria through maintenance documents, "Maintenance Testing and Inspection Instructions (MHI-2293)," attachments 1 and 2, the associated technical specification and testing (TST) form did not document the actual

system conditions which existed. The TST form, in addition to other information, documents the test or inspection required, the test results, and the person who has verified the result of the test. However, it does not document the test conditions used. Discussions of the adequacy of the post-maintenance test associated with the 1-CS-536 will be followed up in the next resident inspector's report.

1-CS-536 is a 4 inch Conval clampseal stop valve and is required to be manually cycled during a fire as postulated in 10CFR50 Appendix R to support the shutdown functions of Unit 2. 1-CS-536 is in series with a similar valve on Unit 2, 2-CS-536. When the valve is closed - the normal at-power position - the pressure normally supplied to the bottom of the valve disc by the charging pump, is not felt at the body-to-bonnet or the valve packing area. Consequently, if one is to properly test this valve's packing or the body-to-bonnet area with the charging pump, it is necessary to place the valve off its seat. The licensee had experienced some seat leakage with this valve during the last operating cycle. Because of seat leakage associated with 1-CS-536, which also contributed to the licensee's unidentified leakrate calculation, the valve was targeted for repair and Job Order A003197 was issued.

The recent body-to-bonnet leakage problem was discovered while the maintenance workers were cycling the Unit 2 CVCS cross-tie discharge isolation valve, 2-CS-536, after a packing adjustment had been performed on the valve on February 27, 1991. When 2-CS-536 was opened, full discharge pressure from the Unit 2 charging pump was applied to the body-to-bonnet area of 1-CS-536, and the leakage from 1-CS-536 was noted by the licensee. Because of this leak, the licensee conservatively declared the Unit 1 Chemical and Volume Control System (CVCS) cross-tie valve to Unit 2 (valve no. 1-CS-536) INOPERABLE. The problem has placed the licensee in a 60 day Limiting Condition for Operation. Both units would have to be shutdown - by April 28, 1991 - to comply with the associated action statement.

The inspector's discussion with the licensee's maintenance staff has indicated that the root cause of the problem may be a cocked installation of a "timing shim." This is a small ring that fits over the stem assembly on the valve to control the valve bonnet position. It is thought the position of the timing shim prevented an adequate body to bonnet sealing surface.

c. The inspector reviewed several maintenance job orders issued to correct various emergency lighting discrepancies found during performance of the emergency lighting units' annual draw-down test. Also, the inspector reviewed the licensee's resolution to problem report (PR) 91-180 which was written to identify a cumulative emergency light failure rate of approximately 19 percent during the test. Review of the job orders and the response to PR 91-180 indicated that the defective emergency lights were repaired in a reasonable time. The licensee is planning to improve the future reliability of these units through more detailed analysis of the failures.

As a part of planned maintenance (PM) task 9, the licensee performs an annual draw-down of 20 lighting units to ensure they can satisfy the 8 hour discharge requirement. For this initial draw-down test, 10 emergency lights from the "general population" and 10 from the "safe shutdown population" are tested. If 2 or more fail during this initial test, an additional 50 units, 25 from the "general population" and 25 from the "safe shutdown" population, are tested. If there are 4 or more failures associated with the 50 lighting units chosen for the second test, the entire lighting unit population is tested. During the most recent emergency lighting test, the licensee had to test all emergency lighting units because of the results of the initial and secondary tests. The cumulative failure rate for the three tests was found to be 18.9 percent. The majority of the emergency lighting unit problems were found to be defective battery packs and bad circuit cards. Other component problems identified included defective lights and incorrect wiring. The inspector noted no discrepancies associated with any of the three job orders for the repair of the emergency lighting units.

The inspector also reviewed the licensee's response to PR 91-180 to determine what safety significance was imposed by the failure rate of approximately 19 percent of the the emergency lighting units. Additionally, the licensee's corrective action, if any, to reduce the failure rate was reviewed. The inspector found that the potential safety significance posed by the failed emergency lights was mitigated by the availability of miner's hats and their mandatory use by procedure. The response to PR 91-180 concluded that the miner's hats provided an adequate level of confidence that the emergency remote shutdown team members could have performed their tasks. Additionally, the inspector noted in the Appendix R emergency lighting meeting notes of January 24, 1991, that the licensee is considering, among other concerns, making changes to PM task 9. The changes are intended to be able to identify, on a sub-component basis, the actual cause for the failure associated with the emergency lights. Additionally, it was decided that the PM task should be modified to re-categorize the "general population" (approximately 50 percent of the units) as not part of the Appendix R program. This was based on recent evaluation of the Plant Safe Shutdown Procedures, input from operators, and practices at other power plants. The licensee is planning to re-categorize some of these emergency lighting units to ensure that the level of lighting is adequate. Maintenance on both the "general population" and "appendix R" lights is planned to be uniformly implemented. PM task 9 is tentatively scheduled to be modified around the end of March 1991, once the required emergency lights for Appendix R locations are confirmed by Operations.

d. The inspector reviewed resolution to Problem Report 91-163, which discussed the possible addition of the wrong type oil to the Unit 2 North Nonessential Service Water (NESW) pump's outboard bearing. Although the NESW pump is a non-safety pump, the inspector noted that the licensee's investigation could not be performed because the Maintenance Department personnel lost the suspected oil sample.

However, the inspector noted that the oil, in both the pump's inboard and outboard bearings, was replaced with the correct type and no abnormal pump operation was noted before or after this event.

No violations, deviations, unresolved or open items were identified.

6. Surveillance (61726, 42700)

The inspector reviewed Technical Specifications required surveillance testing as described below and verified that testing was performed in accordance with adequate procedures, that test instrumentation was calibrated, that Limiting Conditions for Operation were met, that removal and restoration of the affected components were properly accomplished, that test results conformed with Technical Specifications and procedure requirements and were reviewed by personnel other than the individual directing the test, and that deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel.

The following activities were inspected:

a. The inspector reviewed current residual heat removal (RHR) system venting practices when an "excessive" amount of air was found at the end of January 1991, when the licensee was venting the RHR pump. The work was in accordance with routine monthly surveillance test procedure **1-OHP 4030.STP.050W, "West RHR Train Operability Test - Modes 1-4." The event was reviewed to determine the extent of the problem and whether any adverse conditions went unnoticed by the licensee during the outage while the unit was on shutdown cooling. The inspector noted that the unit was on RHR cooling just prior to performance of this test. No problems were noted with either the operation of the RHR pumps (like motor ampere swings), or with any adverse conditions in the rest of the system. The cause for air being found is still under investigation by the licensee. To address preventive actions, the licensee has proposed inclusion of procedure steps to vent the RHR pumps prior to removing them from service in accordance with **1 OHP 4021.017.003,"Removing Residual Heat Removal Loop From Service."

The air problem was found at the end of January 1991, as Unit 1 was coming to the end of a refueling outage. The surveillance (STP. 050W) was also performed at the beginning of January 1991, at which time the pump was vented (in accordance with the procedure). No abnormal conditions were noted and all acceptance criteria were met. During the time between the two monthly surveillance tests (i.e. during mid-January), Unit 1 entered MODE 2 for low power physics testing and the RHR system was removed from service, in accordance with plant procedure **1 OHP 4021.017.003. Unit 1 later made an unplanned mode change to MODE 5 to repair a defective weld on an unisolable main steamline flow instrument. RHR was again placed in service with no abnormalities being noted by the licensee. Following the repair, Unit 1 began power escalation. It was during the startup activities, while Unit 1 was in MODE 3, that the air problem was noted during the routine scheduled monthly surveillance test.

b. The inspector reviewed "Preventive Maintenance and Performance Monitoring Testing For Non Technical Specification Equipment" OHI-5030, Rev. 10, March 19, 1991, because of Problem Report 91-142. It stated that the "Operators are using graffitti markings to monitor and record Unit 2 AB Diesel Generator (DG) lube oil sump tank level." From personal observation, the inspector noted that verifying the oil level by using a tygon hose is inconsistent with the importance of equipment such as the 2AB DG. This is valid even though precise accuracy of the DG tube oil level may not be essential to the proper operation of the machine.

According to test number 73 of Operations Department Surveillance Procedure OHI-5030 Attachment No. 2, operators are required to read the emergency diesel generator lube oil level on a weekly basis. The operators have three different methods for measuring the sump tank lube oil level. The first and preferred method is by the sump tank lube oil level indication on the diesel generator subpanel. The second or alternate method is by using the pressure gauges installed at the lube oil tanks. The third and final method is by using the tygon hose. The inspector accompanied an Auxiliary Equipment Operator to see how this surveillance was accomplished. On Unit 2 AB DG, the method used was the one with the tygon hose. The Unit 2 AB DG sump tank lube oil level could not be verified using the level instrument at the DG subpanel because the instrument had been removed. Additionally, the level could not be verified using the pressure gauges because they were not installed. The inspector noted that a tygon hose was connected to a drain connection on the lube oil sump tank. The oil level was measured with the operators holding the tygon hose vertically. At the time the inspector observed this method being used, the height of the oil level was measured with a yardstick, which was placed on top of the drain connection. It was not clear the yardstick was always placed the same way.

Although subject to some variability, this method did give a rough indication of level to assure adequate presence of oil in the sump tank. It was also noted that Unit 2 AB DG lube oil tank is the only tank which is monitored using the tygon hose. The remaining DG for Unit 2 and the DGs for Unit 1 all have level indications on the DG subpanel. Inspector's review of the problem report indicated that the Unit 2 AB DG lube oil sump tank level indicator cannot be repaired because of unavailability of parts. The potential exists for the same problem to affect the other three DGs. Consequently, the licensee is planning on performing a design change (Minor Mod 184) which will install level gauges to each DG lube oil sump tank. In addition, the existing level instruments for all the DGs will be removed from the tanks and the local panels. Minor Mod 184 is tentatively scheduled for completion on all DGs by May 18, 1991.

c. The inspector observed a portion of surveillance "AB Diesel Generator Operability Test (Train B)," 2-OHP-4030.STP.027AB, Rev. 5, Feb. 21, 1991, and performed a limited review of the procedure. The surveillance was performed to verify the operability of the Unit 2 AB diesel generator (DG) after corrective maintenance. The inspector noted no major discrepancies with either the performance of the surveillance or with the procedure itself. However, the inspector noted both a step in which clarification of the procedure may be beneficial and a material deficiency with the DG emergency trip button.

There was some confusion on how to position the DG cylinder petcocks so that they would be opened during the initial DG roll. Because the petcocks have left-handed threads, when they are turned in the counter-clockwise direction, the petcocks move into the piping. The relative motion of the petcocks as they are opened caused the operator to question the actual position of these petcocks. After discussion with other operators on shift and attempting to verify the position of the petcocks by looking into the blowdown piping with a flashlight, it was determined that the petcocks should move into the piping when they are opened. Subsequent DG roll verified that the petcocks were in their proper position for the DG roll.

Secondly, when the DG emergency trip button was depressed by the operator in step 8.7.4, the emergency trip button fell into the DG control cabinet. Although the DG appeared to have been tripped, the operators realizing what had happened, rushed quickly into the cabinet and pushed the DG emergency trip button back through its opening. The inspector's discussion with the operator after the surveillance found that the emergency trip button collar nut had come loose. It appeared to have been installed backwards so that it only engaged one thread. The operator informed the inspector that the collar nut had been reinstalled properly to increase its thread engagement with the emergency trip button.

d. The inspector observed electricians performing a portion of planned maintenance (PM) task 9 to operationally test the condition of the emergency lights in the plant. The planned maintenance was being performed satisfactorily. The electricians performing the task appeared to be conscientious and identified emergency lights which were defective. The inspector noted no discrepancy with either the performance of the PM or with the planned maintenance procedure used.

PM Task 9 is performed based on a frequency determined by the failures found during the last two tests. Currently, the licensee is performing this PM every 2 months. The PM checked the satisfactory operation of EXIDE emergency lighting units used for both safe shutdown and general lighting purposes. The PM verifies the following features associated with the emergency lighting units:

(1) AC power is available to the emergency lighting unit.

(2) The charger is functioning properly and is providing the float charge to the emergency lighting unit battery.

(3) Emergency lights come on when the AC power is removed.

(4) Emergency lighting is aimed in the proper direction.

(5) Battery for the emergency lighting units can be charged within the required time.

Of approximately 15 emergency battery units observed during this PM Task, the inspector noted only 1 failure. The failed emergency light was not used during safe shutdown of the plant from outside the control room. The inspector's review of the completed PM found that out of approximately 200 emergency lights checked, 14 (approximately 7 percent) had failed for one of the following reasons:

(1) The battery would not return to float charge after a specified period.

(2) The emergency light did not come on after the AC source was removed or it stayed lit for less than the required period of time.

(3) There was no indication of a float charge.

(4) The emergency light did not go off after the AC source was restored.

Job order J.O. A-37375 was written to correct the deficiencies with the emergency lights.

e. During the previous inspection, the inspector reviewed surveillances associated with the Unit 2 Turbine driven Auxiliary Feedwater Pump (see NRC Inspection Report No. 315/90022(DRP); 316/90022(DRP)). The licensee had experienced post-maintenance test (PMT) problems following governor replacement on the Terry Turbine. The inspector noted that several post-maintenance tests were documented on one surveillance document making the PMTs difficult to follow. Consequently, the licensee was asked how aborted surveillances were documented. The inspector learned that the Operations Department had decided to evaluate the practice, as no procedure or instruction existed which addressed how aborted surveillance should be documented. Subsequently, Operating Memo 91-045(I) was released to the Shift Supervisors and discussed the importance of record keeping details and the responsibility for documenting such aborted PMTs. These will be evaluated on a case-by-case basis by the Shift Supervisor. The inspector also noted that, since the release of the memo, the Operations Department has independently checked some surveillance documents. This has identified the need to further evaluate the practice to keep the description of events clear and concise, yet not generate excessive amounts of paperwork. The Operations Department stated that they would keep the inspector informed with the outcome of the evaluation.

No violations, deviations, unresolved or open items were identified.

7. <u>Simulator/Procedure Evaluation (71707, 42700)</u>

During the period February 19-21, 1991, a group of NRC inspectors, including the NRC Region III Projects Branch Chief and Section Chief, and the Senior Resident Inspector assigned to Palisades Plant - each of who has emergency response duties associated with the D. C. Cook plant - joined the D. C. Cook Resident and Senior Resident Inspectors for an evaluation of the plant control room simulator and selected procedures.

Selected procedures and simulator operations were used to familiarize the NRC team with plant behavior during certain evolutions. Additionally, the effectiveness of the procedures applying to the circumstances were assessed. Licensee support consisted of two professional staff trainers and free access to the simulator during the three day evaluation. The trainers operated the simulator scenarios and provided guidance on hardware and procedures.

The following procedures were covered by the evaluation:

02-OHP-4023.E-0	Reactor Trip or Safety Injection.
02-OHP-4023.E-1	Loss of Reactor or Secondary Coolant.
02-OHP-4023.E-2	Faulted Steam Generator Isolation.
02-OHP-4023.ES-1.1	SI Termination.
02-OHP-4023.E-3	Steam Generator Tube Rupture.
02-OHP-4023.ECA-0.0	Loss of All A/C Power.
02-OHP-4023.ECA-1.2	LOCA Outside Containment.
02-OHP-4023.FR-S.1	Nuclear Power Generation/ATWS.
02-OHP-4022.001.002	Loss of Load.
02-OHP-4022.012.004	Dropped Rod.
02-OHP-4022.054.002	Loss of One Condensate Booster Pump.
02-OHP-4022.055.001	Loss of One Feedwater Pump.
02-OHP-4023.001.006	Loss of Control Air.
02-OHP-4024.208 (Drop 8)	Pressurizer Spray Valve Malfunction.

No substantive discrepancies were identified in any of the procedures. Some comments were provided to the licensee representatives for their consideration and, if deemed appropriate, further follow up action.

8. Engineering and Technical Support (93702)

The inspector monitored engineering and technical support activities at the site and, on occasion, as provided to the site from the corporate office. The purpose was to assess the adequacy of these activities in supporting other functional areas.

a. The inspector reviewed the licensee's investigation of the TDAFW pump electrical overspeed event following the Unit 2 trip on March 13, 1991. The licensee has experienced previous overspeed problems with the Unit 2 TDAFW pump. The details of the Unit 2 TDAFW pump were discussed in NRC Inspection Report 315/90027;316/90027 (DRP). As a result of previous problems, the TDAFW pump had been placed on an increased frequency test schedule and had successfully passed those tests. The inspector found that the plant engineer's investigation was comprehensive and thorough. The March 13, 1991, overspeed was not caused by a previously identified problem. The plant engineering department was not able to positively identify the root cause(s) for the overspeed trip. However, they were able to determine that the TDAFW pump was operating normally for a period of time before tripping on electrical overspeed. Additionally, the TDAFW pump could be restarted from the control room in the event it was needed. Four successful restarts following the TDAFW pump trip appeared to indicate that the trip may have been spurious. This investigation was noteworthy in that the auxiliary feedwater system engineer was attending school during the investigation. The plant engineering department was able to redirect its resources to aggressively investigate the TDAFW pump trip. The series of tests and inspections performed by the licensee included:

(1) Analysis of pre- and post-trip steam generator pressures and levels to determine whether any conditions existed that would have resulted in the TDAFW pump trip.

(2) Check of the TDAFW pump magnetic sensor to ensure the electrical trip signal circuitry was operating properly.

(3) Inspection of the governor valve linkage and stem for binding or corrosion.

(4) Inspection of Woodward governor oil for water contamination.

(5) Inspection of steam traps on the TDAFW pump supply piping to ensure proper operation.

(6) Testing of the TDAFW pump electrical overspeed trip.

The licensee performed numerous full speed start tests and noted no abnormalities with this or any of the above tests and inspections. Additionally, an electrical engineer reviewed the TDAFW pump electrical system for any link with the concurrent offsite electrical power disturbances. The review found no apparent link. There are several points of electrical isolation (such as transformers and a battery charger) between the "system" and the N-Train battery. The battery provides the electrical power for the TDAFW pump components.

b. The inspector reviewed the investigation into the boric acid heat trace temperature alarms and the Unit 1 emergency boration flowpath blockage. Although there were problems with the boration systems in both units, Unit 1 appeared to have more significant problems during this inspection period. The inspector found that the lack of interim corrective action taken by the licensee - while the cause for the initial blocking of the Unit 1 emergency boration flowpath was being investigated - contributed to the second instance of emergency boration flowpath blockage.

The Boron Make-up system is used as a means for controlling reactor reactivity. The system is designed to supply concentrated boric acid (via the charging pumps) - to the reactor coolant system - during some abnormal plant conditions. Two separate events, involving some degree of blockage of the Unit 1 "emergency" boration flowpath occurred on February 12 and March 1, 1991. At least one of the boric acid flowpaths, normal or emergency, must be OPERABLE while the unit is at power per Unit 1 Technical Specifications 3.1.2.2.a. Part of the operability verification is that the temperature of the heat traced portion of the flowpath not fall below 145 degrees Fahrenheit.

The licensee - concerned that wet insulation caused by several boric acid leaks could lead to loss of insulation capability and a boric acid hardening problem in the piping - issued job orders to repair the leaks. The licensee removed Unit 1 normal boration flowpath from service on February 12, 1991, to repair two components identified as a source of boric acid leakage. This was believed to be causing excessive heat trace alarms. One component was 1-QFC-411 (electric flow transmitter) and the other was 1-CS-487 (inlet shutoff diaphragm valve to 1-QFC-411). Because the work isolated the normal boration pathway, operators attempted to verify the operability of the emergency boration pathway. A possible blockage in the emergency boration line was identified and a job order was written. To determine if blockage existed, operators were requested to test the emergency boration flowpath using a primary water flush lineup. Initially, only 4 gpm of flow was indicated. However, after approximately 25 seconds, a flow of approximately 40 gpm was indicated on the emergency boration line flow meter. This identical lineup had been used by a previous night shift to determine whether the piping was blocked. The licensee's discussion with the night shift, however, found that they had throttled a valve in the primary water flush pathway. Therefore, it was concluded that sufficient pressure might not have been imposed on the blocked portion of the piping. Additionally, on February 13, 1991, the licensee performed a surveillance procedure on Unit 2's emergency boration line to verify that it was not blocked.

The primary water flush normally delivers a higher pressure than the boric acid transfer pump because of differences in the system valve lineup. Consequently, in the event the emergency boration pathway was blocked, it could not be cleared from the control room using the boric acid transfer pump. Manual valve operations requiring the primary water system must be used. The manual method used to clear the emergency boration pathway could cause unnecessary delay in emergency boration pathway use. Several licensee procedures, including "Response To Nuclear Power Generation/ATWS," 01-OHP 4023.FR-S.1, reference this use.

At first, the corrective actions employed by the licensee seemed to be effective in preventing similar boric acid hardening problems. But another event occurred during March 2-3, 1991, when the licensee brought Unit 1 down to 88-percent power for main turbine control valve testing. The power reduction was accomplished using the "normal" boration flowpath. The normal flowpath was declared INOPERABLE a few hours after reaching 88-percent power. Heat tracing on the line was unable to keep the temperature above 145-degrees Fahrenheit. The Unit supervisor decided to check flow through the emergency boration flowpath because of the past problems he had personally experienced with that part of the system. When the inlet isolation valve was opened, no flow was indicated. The unit was placed in a 72-hour Limiting Condition for Operation for INOPERABLE boric acid flowpath. Several hours later, the licensee successfully flushed the emergency boration flowpath with pure "primary" water. Subsequently, the normal and emergency flowpath were verified OPERABLE by checking proper flow through the entire system.

Because of the emergency boration flowpath blockage problems, the operations department initiated actions to leave pure water in the emergency boration line. The potential effect of leaving pure water in the emergency line was evaluated by both the licensee's corporate engineers and Westinghouse and found to be acceptable.

The cause of the apparent blockage problem was not absolutely determined. A multi-departmental group, headed by the system engineer, continues to work toward resolution of the heat trace boration piping blockage problems. The group is chartered to study current work practices and testing methods to improve the reliability of the system. Additionally, the group is in process of conducting a coordinated plan to address heat trace issues.

Pending confirmation that Unit 1's normal boration flowpath was operable when the emergency boration flowpath appeared to have been blocked, compliance to Technical Specification 3.1.2.2.a is in question. Until a satisfactory resolution to this question has been reached, this will remain an unresolved item (Unresolved Item 50-315/91004-01).

c. Several of the licensee's internal corrective action documents (called "Condition Reports") were noted that were related to problems with the containment dewpoint monitors. Because several Condition Reports were generated in a short time, the inspector checked into licensee actions to effectively address the problems. The licensee had performed an extensive review of this system. A design change to replace the old instrumentation with "state-of-the-art" equipment has been scheduled for both units. The inspector's review found that at no time was the licensee in violation of the Technical Specifications. Several alternatives to the design problem are still being evaluated. In the meantime, the licensee will continue to monitor the system and make system repairs as necessary.

Since the end of 1990, several Condition Reports describing INOPERABLE red or blue pens were generated. (The pens record the dewpoint sample results from inside containment.) A job order history search found that since the beginning of 1989, about 40 Job Orders were written to correct problems associated with these instruments. Technical Specifications require either containment dewpoint monitoring or containment atmosphere gaseous radioactivity monitoring be OPERABLE during MODES 1-4. Such monitoring capability provides for detection of deviations from normal containment environmental conditions (humidity in the case of the dewpoint monitors). This could be indicative of minor reactor coolant pressure boundary leakage. The problems with the containment dewpoint monitors are partly attributed to old and obsolete equipment and to the design of the system.

No violations, deviations, unresolved or open items were identified.

9. Security (71707)

Routine facility security measures, including control of access for vehicles, packages and personnel, were observed. Performance of dedicated physical security equipment was verified during inspections in various plant areas. The activities of the professional security force were occasionally examined or reviewed, and interviews were occasionally conducted with security force members.

a. On February 19-22, 1991, NRC Region III conducted an inspection of the licensee's Fitness-For-Duty (FFD) program required by 10 CFR Part 26. The inspection is documented in NRC Inspection Report No. 50-315/91005(DRSS); 50-316/91005(DRSS).

   Based on the selected examination of key elements of the licensee's FFD Program, it was concluded that the licensee is satisfying the general performance objectives of 10 CFR 26.10. Several program strengths were identified. Program strengths included strong senior management support and oversight, aggressive involvement and quality of the licensee's Quality Assurance FFD audit, active canine program for detection of controlled substance, Employee Assistance Program (EAP) benefits for site contractor, and an aggressive proactive alcohol "Odor Identification" program. Management support for the FFD program was apparent as demonstrated by the professionalism, competency, and dedication of the staff involved in the administration of the FFD program.

b. The licensee reported a Fitness For Duty event to the NRC this inspection period. The event involved a confirmed positive random drug test for the presence of Opiates without sufficient explanation as to its presence. The individual had been assigned firewatch responsibilities. The event description was forwarded to NRC Region III Security Specialists for follow-up action.

No violations, deviations, unresolved or open items were identified.

10. Safety Assessment/Quality Verification (37701, 38702, 40704, 92720)

The effectiveness of management controls, verification and oversight activities, and conduct of jobs observed during this inspection period, was evaluated.

The inspector frequently attended management and supervisory meetings involving plant status and plans which focused on proper coordination among Departments. The plant recently established an integrated scheduling program termed the "Plan of the Day," which will be used to coordinate departmental activities on a daily basis.

The results of licensee auditing and corrective action programs were routinely monitored by attendance at Problem Assessment Group (PAG) meetings. Condition Reports, Problem Reports, Radiological Deficiency Reports, and security incident reports were also reviewed. Inspectors found that, in general, the PAG successfully identified and resolved potentially safety significant problems in a timely fashion. As applicable, corrective action program documents were forwarded to NRC Region III technical specialists for information and possible follow-up evaluation.

No violations, deviations, unresolved or open items were identified.

11. Unresolved Items

Unresolved Items are matters about which more information is required in order to ascertain whether they are acceptable items, violations, or deviations. An unresolved item disclosed during the inspection is discussed in Paragraph 8.b. of the report.

12. Management Interview (30703)

The inspectors met with licensee representatives (denoted in Paragraph 1) on March 21, 1991, to discuss the scope and findings of the inspection. In addition, the inspectors also discussed the likely informational content of the inspection report with regard to documents or processes reviewed by the inspector during the inspection. The licensee did not identify any such documents/processes as proprietary.