U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Nos. 50-315/94022(DRP); 50-316/94022(DRP)

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

Licensee: 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: October 30 through December 16, 1994

Inspectors: J. A. Isom
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1/5/95
Date

Inspection Summary: Inspection from October 30 through December 16, 1994 (Report Nos. 50-315/94022(DRP); 50-316/94022(DRP))

Areas Inspected: Routine, unannounced safety inspection by the resident and region-based inspectors of: action on previous inspection findings, operational safety verification, onsite event follow-up, current material condition and housekeeping, radiological controls, security, regional requests, maintenance activities, LCO management, surveillance activities, starting air compressors, and nozzle weld inspection.

Results: Of the 12 areas inspected, one inspection follow-up item was identified that pertained to emergent corrective maintenance (paragraph 5.a.3) There also was one unresolved item identified that pertained to LCO management (paragraph 5.b.) One non-cited violation was identified that pertained to the draining of the reactor coolant system (paragraph 3.a.1). The following is a summary of the licensee's performance during this inspection period:

Plant Operations: Overall, operator performance during Unit 2 draindown for mid-loop and plant start-up evolutions was good. However, while reviewing November 23, 1994, control room logs, the inspectors noted that reactor coolant system draining was commenced with level instruments having a difference of 4.8 inches which was contrary to Procedure 02-OHP-4021.002.005.

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In addition, the operators experienced the following problems during attempts to parallel the main generator to the grid:

- The operators were not aware that an alarming annunciator on the main generator alarm panel would prevent applying field voltage to the main generator after the exciter breaker was shut.

- The operators prematurely returned the synchronous selector switch to the "off" position which prevented the "A2" breaker from closing.

The inspectors observed that, overall, plant housekeeping and material condition was good during the inspection period. However, the inspectors found that some of the Unit 2 areas had not been restored to the licensee's housekeeping standards following the completion of the refueling outage. In addition, the inspectors identified a concern regarding debris in Unit 2 containment which was discovered by QC inspectors after completion of the Operations Department's closeout inspection prior to entry into Mode 4.

Maintenance and Surveillance: Overall, performance during the period was good. However, the inspectors identified the following two examples of less than optimal LCO management during the period:

- The licensee unnecessarily entered a 72 hour LCO per TS 3.6.4.1 when both trains of Unit 1 post accident containment hydrogen monitoring system (PACHMS) were removed from service for preventive maintenance.

- On November 16, with Unit 2 in Mode 5, the licensee identified a body to bonnet leak on a valve common to both boric acid storage tanks injection flow paths. Unit 2 was in Mode 5 from November 16 to November 20 and then between November 22 and 28 to perform other emergent corrective maintenance. On November 30, 1994, while Unit 2 was in Mode 3, the licensee removed both injection flow paths from the boric acid storage tanks from service to repair the body to bonnet leak. This maintenance activity could have been performed while the plant was in Mode 5, eliminating the need to enter a LCO condition.

The inspectors concluded that the acceptance criteria used for the post maintenance test after replacing a mechanical governor on a emergency diesel generator was not as rigorous as the TS surveillance requirements.

Engineering and Technical Support: The licensee demonstrated a positive commitment to safety by voluntarily performing an examination of the reactor head penetration welds, as there was no requirement by the ASME Code Section XI or the NRC to examine these welds.

Plant Support: The licensee made a notification pursuant to 10 CFR 50.72, after identifying that temporary unescorted access had been previously granted to an individual, although information was available that the individual had been denied access at another facility. A regional security inspector performed a special inspection regarding this event, and the results will be documented in a separate report.

DETAILS

1. Persons Contacted:

*A. A. Blind, Site Vice President/Plant Manager
K. R. Baker, Assistant Plant Manager/Operations Superintendent
*L. S. Gibson, Assistant Plant Manager-Technical
J. E. Rutkowski, Assistant Plant Manager, Support
T. P. Beilman, Maintenance Superintendent
P. F. Carteaux, Training Superintendent
D. L. Noble, Radiation Protection Superintendent
T. K. Postlewait, Site Engineering Support Manager
P. G. Schoepf, Materials Management Superintendent
J. S. Wiebe, Quality Assurance & Control Superintendent
L. H. Vanginhoven, Project Engineering Superintendent
*G. A. Weber, Plant Engineering Superintendent
A. A. Lotfi, Site Design Superintendent
W. M. Hodge, Plant Protection Superintendent
S. R. Gane, Administrative Compliance Coordinator
L. L. Smead, Security Operations Supervisor

*Denotes those individuals attending the exit interview conducted on December 19, 1994.

The inspectors also had discussions with other licensee employees, including: members of the technical and engineering staffs, reactor and auxiliary operators, shift engineers and foremen, maintenance personnel, and contract security personnel.

2. Action on Previous Inspection Findings: (92701)

a. (Closed) Inspection Follow-up Item (50-315/92003-01; 50-316/92003-01(DRS)): The EDSFI team noted that old short circuit calculation results did not model actual electrical distribution system conditions as well as could be obtained from computerized calculation techniques. The licensee committed to perform critical short circuit fault calculations using a recently obtained short circuit analysis software program.

The inspectors reviewed the new calculations that used the new short circuit analysis software program. The review determined that certain 4 kV switchgear exceeded the momentary duty rating by as much as 20.6 percent. The licensee stated that the electrical engineering group had this item under review. The inspectors concluded that the probability of exceeding the breakers momentary interrupting rating was very low. In addition, the inspectors concluded that the redundant electrical train would be available and would not be affected by a common mode fault.

Based on minimal safety significance, and continuing licensee reviews, this item is closed.

b. (Closed) Inspection Follow-up Item 50-316/94002-02(DRP): As discussed in Inspection Report 50-315/94002;50-316/94002(DRP), main turbine lube oil pressure fluctuations may have been responsible for a Unit 2 turbine trip that occurred during startup in January 1994.

During the recent Unit 2 refueling outage, the licensee disassembled and refurbished the discharge check valves for both the auxiliary and shaft driven lube oil pumps. These valves were suspected of contributing to the main turbine lube oil pressure fluctuations while both pumps were running. The system engineer indicated that the position of LO-189, a valve that supplies oil from the lube oil coolers to the air-oil pump, may also affect the pressure fluctuations. After refurbishment of the discharge check valves, the inspectors observed reduced magnitude main turbine lube oil fluctuations. The licensee will continue investigations to determine the appropriate position of LO-189. The inspectors have no further concerns.

c. (Open) Unresolved Item 50-315/94009-01(DRP): The inspectors toured Unit 1 containment following a licensee close-out tour in May 1994 and were concerned with the amount of foreign material present.

Prior to entering Mode 4, after the completion of the Unit 2 refueling outage, the licensee performed a cleanliness inspection of the containment using procedure 02-OHP-4030.001.002, Revision 9, "Containment Inspection Tour." This procedure was used to satisfy the requirements of Technical Specification (TS) 4.5.3.1. The Operations Department completed the inspection and signed off that all areas were acceptable. Subsequently, as required by 02-OHP-4030.001.002, Quality Control (QC) personnel performed a containment tour on November 20, 1994, and identified numerous items that should have been removed from containment to ensure compliance with TS 4.5.3.1. Condition Report (CR) 94-2394 was initiated to document these findings. The items identified included nuts, washers, bolts, a glove, and tape. These items were removed while Unit 2 was in Mode 5.

On November 30, 1994, following another licensee's closeout inspection, the inspectors observed that a significant improvement had occurred with respect to housekeeping in the containment basement. Only one item, a small coil of wire that was subsequently removed by the licensee, was identified by the inspector during the tour.

The inspectors remain concerned, however, that the Operations Department considered the condition of containment acceptable prior to an QC inspection November 20, 1994. This item will remain open pending further review by the inspectors.

No violations or deviations were identified.

3. Plant Operations:

The licensee operated Unit 1 at full power throughout the inspection period with no significant operational problems.

The licensee began the inspection period with Unit 2 in Mode 5 with a refueling outage in progress. The licensee completed the outage approximately 45 days beyond the scheduled end date due to emergent work identified during plant heat-up. This work included replacement of steam generator manway cover gaskets, Reactor Coolant Pump No. 22 motor, repair of a body-to-bonnet leak on the residual heat removal (RHR) hot leg isolation valve (IMO-128), and repair of a body to bonnet leak on a RHR to safety injection crosstie valve (IMO-316). On December 11, the licensee paralleled the unit to the grid, ending the 100 day outage. Shortly after paralleling to the grid on December 11, Unit 2 tripped from approximately 20 percent power due to a high level in the Right Moisture Separator Reheater (RMSR). This event is discussed in paragraph 3.b.2) of this report. The licensee returned the unit to service on December 13, and Unit 2 was operating at about 50 percent power at the end of the inspection period.

a. Operational Safety Verification: (71707)

The inspectors verified that the facility was being operated in conformance with the licenses and regulatory requirements, and that the licensee's management control system was effective in ensuring safe operation of the plant.

On a sampling basis the inspectors: verified proper control room staffing and coordination of plant activities, verified operator adherence with procedures and technical specifications, monitored control room indications for abnormalities, verified electrical power was available, and observed the frequency of plant and control room visits by station management. The inspectors reviewed applicable logs and conducted discussions with control room operators throughout the inspection period. The inspectors observed a number of control room shift turnovers. The turnovers were conducted in a professional manner and included log reviews, panel walkdowns, discussions of maintenance and surveillance activities in progress or planned, and associated LCO time restraints, as applicable. The inspectors made the following observations with regards to operator performance during the inspection period:

1) On November 22, 1994, draining of the RCS was commenced to a half-loop level to support replacement of steam generator manway gaskets. Delays were incurred throughout the evolution because of discrepancies between reactor vessel level instruments. The drain-down was completed on November 25, 1994.

The inspectors monitored portions of the draindown evolution from the control room and verified that the licensee implemented requirements of procedures PMI-4070, "Criteria For Operating at a Reduced Reactor Coolant System Inventory," and 02-OHP-4021.002.005, "RCS Draining." While reviewing control room logs from November 23, 1994, the inspectors noted that draining commenced with level instruments NLI-132 and NLI-112 reading 620.2 and 619.8 feet, respectively, a difference of 4.8 inches. Procedure 02-OHP-4021.002.005 contained a precaution that if indication from these instruments differed by more than 4 inches, drain operations should be stopped and the discrepancies resolved. This log entry was brought to the attention of the shift supervisor.

Although the licensee failed to stop draining the RCS as required by procedure 02-OHP-4021.002.005, the safety significance of the problem met the criteria for a Severity Level V violation. The licensee issued Condition Report (CR) 94-2531 to investigate this issue and any comprehensive action to prevent recurrence will be identified in the CR. Therefore, the violation is not being cited because the criteria specified in Section VII.B.1 of the "General Statement of Policy and Procedure for NRC Enforcement Actions," (Enforcement Policy, 10 CFR Part 2, Appendix C), were satisfied.

With the above exception, the operators responded to the problems with the level instruments in a conservative manner, completing the draindown evolution without incident.

2) The inspectors observed an uneventful Unit 2 turbine startup on December 10, 1994. The following problems were observed by the inspectors during Unit 2 turbine startup on December 13 and 14:

- The operators were unable to shut the exciter field breaker to the main generator resulting in the turbine protection system initiating a turbine trip. Because reactor power was below 10 percent, the turbine trip did not initiate a reactor trip. The licensee wrote CR 94-2509 to investigate this problem.

- The operators were not aware that the alarming annunciator, "manual voltage regulator failure," on the main generator alarm panel, would prevent applying field voltage to the main generator after the exciter breaker was shut. Consequently, once the exciter breaker was shut, field voltage was not applied to the main generator. After resetting the manual voltage

regulator, the next operating shift successfully applied the field voltage to the generator.

- The operators prematurely returned the synchronous selector switch to the "off" position which prevented the "A2" breaker from closing. The "A2" breaker ties the Unit 2 main generator to the Unit 2 switchyard. As a result, the operators had to repeat the paralleling operation. CR 94-2510 was written to investigate this problem.

In all of these situations, onshift Operations Department management addressed each problem in an appropriate and conservative manner.

b. Onsite Event Follow-up: (93702)

During the inspection period, the licensee experienced several events, some of which required prompt notification of the NRC pursuant to 10 CFR 50.72. The inspector pursued the events onsite with licensee and/or other NRC officials. In each case, the inspectors verified that any required notification was correct and timely. The inspectors also verified that the licensee initiated prompt and appropriate actions. The specific events were as follows:

1) On November 18, 1994, the licensee made a notification after identifying that temporary unescorted access had previously been granted to an individual, despite having available information that the individual had been denied access at another facility.

   The licensee originally granted the individual access in February 1994. The licensee's background investigation identified the tainted record after the individual left the site; however, licensee personnel failed to take appropriate action. The licensee then reinstated temporary access to the individual in September 1994.

   In response, an NRC regional security inspector performed a special inspection to investigate the event. Results of the inspection will be documented in a separate inspection report.

2) At 5:06 p.m. on December 11, 1994, Unit 2 reactor tripped from a main turbine trip. At the time of the event, reactor power was about 19 percent and the operators were increasing power to about 30 percent. The licensee's investigation of the event found that the turbine trip was caused by a high-high level on the Right Moisture Separator Reheater (RMSR). After

the trip, all safety systems operated as designed. The licensee initiated CR 94-2504 and convened a troubleshooting team to investigate the cause for the reactor/turbine trip.

The troubleshooting team could not positively determine the root cause for the high-high level trip on the RMSR. The team determined that the instrument that initiated the trip, 2-HLS-418R, functioned properly. However, the RMSR drain tank high and high-high level alarms were found not working and were repaired by the Instrumentation and Control (I&C) technicians. The RMSR drain tank receives the steam drain from the RMSR, and the drain tank high and high-high level alarms would function as precursors to a RMSR high-high level trip. I&C technicians also verified that the left moisture separator reheater (LMSR) drain tank high and high-high level alarms functioned properly.

The troubleshooting team performed tests to ensure that the piping from the RMSR drain tank to the "C" condenser was clear of blockage. The team was concerned that debris may have been introduced into the system from maintenance conducted during the refueling outage. The test verified that the piping from the RMSR drain tank to the "C" condenser was clear.

Although the cause for the turbine trip was never positively identified, the troubleshooting team recommended that Unit 2 be allowed to restart based on the results of the investigation. The licensee monitored the MSR drain tank level during the subsequent power escalation on December 13, 1994 and experienced no problems with the RMSR level. The inspectors will review the licensee's Licensee Event Report (LER) to ensure that adequate corrective actions will be taken.

3) On December 16, 1994, the licensee identified that incorrect information was provided to the NRC for an exemption to Appendix R, Section III.G.2 for fire zone 29G, screenhouse auxiliary motor control center room. The exemption request stated that both trains of essential service water for each unit would be protected from the effects of fire in that zone. Contrary to this, the licensee identified that cables associated with the power supply to each ESW pump discharge valve could be lost, resulting in the valves failing in the as-found position. The licensee had been performing compensatory fire watches in the area since June 1992 due to fire barrier concerns. The inspectors will review the licensee's LER submittal to assess the adequacy of the root cause determination and corrective action.

c. Current Material Condition and Housekeeping: (71707)

The inspectors performed plant and selected system and component walkdowns to assess the general and specific material condition of the plant, to verify that work requests had been initiated for identified equipment problems. Walkdowns included an assessment of buildings, components, and systems: identification, tagging, accessibility, fire and security door integrity, scaffolding, radiological controls, and unusual conditions. Unusual conditions included but were not limited to water, oil, or other liquids on the floor or equipment; indications of leakage through ceiling, walls or floors; loose insulation; corrosion; excessive noise; unusual temperatures; and abnormal ventilation and lighting.

The inspectors also monitored the status of housekeeping and plant cleanliness for fire protection and protection of the safety-related equipment from intrusion of foreign matter. The inspectors observed that overall plant housekeeping and material condition was good during the inspection period. The inspectors found that some of the Unit 2 areas had not been restored to the licensee's housekeeping standards following the completion of the refueling outage. In addition, the inspectors were concerned that debris in Unit 2 containment was discovered by QC inspectors after completion of Operations Department's closeout inspection prior to entry in Mode 4 (See paragraph 2.c).

d. Radiological Controls: (71707)

The inspectors verified that personnel were following health physics procedures for dosimetry, protective clothing, frisking, posting, etc., and randomly examined radiation protection instrumentation for use, operability, and calibration.

f. Security: (71707 & 81070)

Each week during routine activities or tours, the inspectors monitored the licensee's security program to ensure that observed actions were being implemented according to the approved security plan. The inspectors noted that persons within the protected area displayed proper photo-identification badges and those individuals requiring escorts were properly escorted. The inspectors also verified that checked vital areas were locked and alarmed. Additionally, the inspectors also observed that personnel and packages entering the protected area were searched by appropriate equipment or by hand.

On November 18, 1994, the licensee identified that temporary unescorted access had previously been granted to an individual, despite information available that the individual had been denied access at another facility. Details are provided in paragraph 3.b.1).

No violations or deviations were identified.

4. Regional Requests: (92701)

In response to a request from the Region III Office, the inspectors conducted a review of the licensee's procedures and practices regarding the removal of equipment from service for on-line scheduled maintenance.

5. Maintenance/Surveillance: (62703 & 61726)

a. Maintenance Activities: (62703)

Routinely, station maintenance activities were observed and/or reviewed to determine compliance with approved procedures, regulatory guides, industry codes, industry standards, and Technical Specifications (TS).

The following items were also considered during this review: Limiting Conditions for Operation requirements met while components or systems were removed from service; approvals obtained prior to initiating work; functional testing and/or calibrations performed prior to returning components or systems to service; maintenance of quality control records; and activities accomplished by qualified personnel. Portions of the following Job Order (JO) activities were observed and reviewed:

JO C0027388 "2-IMO-316 Disassemble To Replace Pressure Seal"
JO C0027170 "2-CS-423S, Replace Diaphragm"
JO C0027078 "Unit 1 CD EDG, Replace Woodward Governor"
JO R0035747 "Calibrate Alarm Switch 2-QDA-251"
JO R0036004 "Replace Solenoid 1-XSO-613"
JO C0027334 "2-IMO-128, Repair Bonnet/Body Leak"
JO C0026505 "Troubleshoot/Repair Generator Field Ground Alarm"

1) Leak from IMO-128, Residual Heat Removal (RHR) Hot Leg Isolation Valve (JO C0027334):

On November 30, 1994, licensee personnel identified a leak during a full temperature and pressure walkdown on IMO-128, the first valve between the reactor coolant system (RCS) hot leg and the RHR system. The leak was about two drips per second with the insulation installed on the valve. The licensee removed the insulation and found a small quantity of water coming out of the body-to-bonnet joint area of the valve. The licensee initially attempted to stop the leak by increasing the torque on the flange studs but was unsuccessful. As a result, the licensee decided to perform a temporary leak repair using the Furmanite process because disassembly of the valve for a gasket replacement would have required a full core off-load of the fuel in the reactor vessel.

The licensee installed a clamp under temporary modification 2-94-35. The clamp was seal welded to the valve to retain the sealant compound around the valve during the injection process. The inspectors observed portions of the injection process and found no problems. Because of the Plant Nuclear Safety Committee's concern over whether the valve would stroke after the Furmanite process, the licensee performed the injection in Mode 5. After the injection was completed, the operators successfully stroked IMO-128. The inspectors accompanied the operators on another full-temperature and pressure walkdown on December 7, 1995, and verified that the valve no longer leaked.

The inspectors reviewed the licensee's plans and procedures and determined that:

- The calculations (DCC-02-LS-01N) for stresses on the valve and on the clamp during sealant injection were acceptable. The weight added by clamp and sealant would be seismically acceptable and the clamp would not become a missile in the event of an earthquake.

- There would be no additional injections without review by engineering.

- The licensee had reviewed the effect of borated water on body/bonnet studs.

- There was no drilling or other reduction of structural strength of the valve.

- The licensee wrote Action Request (AR) C0027358 to perform a permanent repair to 2-IMO-128 during the 1996 Unit 2 RFO.

The licensee's review of past job orders found that this valve was repaired due to a similar body-to-bonnet leak in 1988. At the end of the inspection period, the licensee had decided to perform a weld of the "c-ring canopy" to provide, in addition to the gasket, another leak barrier around the body-to-bonnet joint area. This c-ring canopy would then be periodically replaced during RFOs.

2) <u>Emergency Diesel Generator (EDG) Governor Replacement (J00027078):</u>

On November 10, 1994, following completion of scheduled corrective maintenance, the Unit 1 "CD" EDG failed a post-maintenance operability surveillance. After opening the 4 kv output breaker (1T11C3) to remove the EDG from the safety bus, the operators observed that the EDG frequency and field

voltage had pegged high and the engine speed decreased to 50 rpm. The operators then manually tripped the EDG.

Following troubleshooting, the licensee determined that the mechanical governor had failed. The governor was replaced with a governor previously removed from Unit 2 EDG AB during the most recent refueling outage. The governor was removed for preventive maintenance but had not yet been refurbished. The Post Maintenance Test (PMT) consisted of three fast speed starts of the EDG, each of which were followed by application of the 1750 kw load bank. Following the three fast starts, the licensee performed a slow start and one hour run at full load (3500 kw) per 01-OHP.4030.STP.027CD, "CD Diesel Generator Operability Test (Train A)." The inspectors determined that the PMT was based on a dedication plan for a new or refurbished governor received from the vendor.

The acceptance criteria for testing required that EDG speed not exceed 109 percent of rated speed during startup and that speed was recovered after application of the load bank. The licensee installed a chart recorder to monitor engine speed during the testing.

The inspectors compared the PMT with TS surveillance requirements that could be impacted by the governor replacement. The inspectors noted that TS surveillance 4.8.1.1.2.e.2 required the EDG be capable to reject a load greater than or equal to 600 kw while maintaining a frequency at 60 +/- 1.2 HZ. In addition, TS surveillance 4.8.1.1.2.e.3 required that the EDG be capable to reject a load of 3500 kw without exceeding 75 percent of the difference between nominal speed and the overspeed trip setpoint. These surveillance requirements were required to be performed on an 18 month frequency, and not necessarily after replacement of the governor.

The inspectors concluded that the acceptance criteria used for the PMT were not as rigorous as the TS surveillance requirements. However, the inspectors reviewed the charts of the engine speed recorded during the testing and did not note any erratic behavior during the engine starts and load applications/rejections which would question the ability of the EDG to perform as designed. The inspectors have previously identified an Unresolved Item (50-315/94014-06) pertaining to PMT and will continue to monitor licensee activities in this area.

3) Emergent Work

As previously stated, the licensee completed a Unit 2 refueling outage approximately 45 days beyond the scheduled

end date due to emergent work identified during plant heat-up. This work included replacement of steam generator manway cover gaskets and repair of a body to bonnet leak on a RHR to safety injection crosstie valve (IMO-316). The effectiveness of maintenance activities during the refueling outage is considered an inspector followup item pending further review of emergent corrective maintenance (50-316/94022-01 (DRP).

b. Limiting Condition for Operation (LCO) Management:

In response to an industry concern, the inspector reviewed the licensee's planned maintenance activities during periods that required entry into TS LCO action statements. The inspectors noted two examples where activities resulted in unnecessary unavailability time of TS required systems.

1) On November 14, 1994, the licensee entered a 72 hour LCO per TS 3.6.4.1 after removing both trains of Unit 1 Post Accident Containment Hydrogen Monitoring System (PACHMS) from service for preventive maintenance. The inspectors noted that the licensee review required by PMSO.122 did not provide justification for removal of both trains simultaneously.

   During follow-up discussions, the licensee indicated that both trains were removed rather than use a check valve in the system as containment isolation. The check valve was located on the containment return line common to both trains and was in series with two parallel valves, one designated for each train. To maintain containment integrity during replacement of the solenoid on one of the valves, ECR-20, the licensee closed an upstream manual valve which isolated both trains.

   The inspectors determined that the licensee could have closed and de-energized ECR-20 with a stem lock installed to prevent the valve from inadvertently opening to maintain containment integrity. By using this alignment, the licensee would have maintained the operability of Train A.

2) On November 30, 1994, while Unit 2 was in Mode 3, the licensee removed both injection flow paths from the boric acid storage tanks from service to repair a body to bonnet leak on a valve common to both paths, 2-CS-423S. The removal of both flow paths required entry into a 72 hour LCO per TS 3.1.2.2.a. Licensee management approved the voluntary LCO entry to repair the valve, as required by PMSO 122, the previous day. The inspectors concluded that the licensee should have considered working the valve while the unit was in Mode 5 when the LCO statement per TS 3.1.2.2.a was not applicable. The scheduled duration of the work

activity was 17 hours. The inspectors reviewed this maintenance activity and determined that:

- On November 16, 1994, while in Mode 5, the licensee identified the required maintenance for 2-CS-423S. Unit 2 was in Mode 5 until November 20 and again between November 22 and 28 to perform emergent corrective maintenance.

- On December 1, approximately 28 hours after entering the LCO, Operations discovered during a review of the job status that an additional work activity, replacement of filter 2-QC-12, had been added to the valve repair clearance without management approval. The licensee apparently experienced some delays in completing the filter replacement, extending the period of time in the TS action statement. Since the filter replacement did not require the removal of the flow paths from service, the licensee prepared a new clearance for the activity, restored the flow paths, and exited the LCO about 20 hours later than scheduled. The licensee initiated CR 94-2452 to document and investigate the deficiency.

  The inspectors reviewed PMSO.122 and noted that the procedure did not address what actions were required when the scheduled duration of the LCO entry was exceeded with work still in progress. However, the inspectors concluded that the operators were ultimately responsible for plant system status and should have displayed a questioning attitude by checking on the status of the work when the scheduled duration was reached. This would have prevented the excessive unavailability time of the boration flow paths.

Entry into LCOs to perform maintenance activities is considered an unresolved item pending further review by the NRC (50-315/94022-02; 50-316/94022-02(DRP).

c. Surveillance Activities: (61726)

During the inspection period, the inspectors observed technical specification required surveillance testing and verified that testing was performed in accordance with adequate procedures, instrumentation was calibrated, results conformed with technical specifications and procedure requirements and were reviewed, and any deficiencies identified during the testing were properly resolved. The inspectors also witnessed portions of the following surveillances:

02-IHP.4030.SMP.212, "Pressurizer Pressure Protection Set II Functional Test And Calibration," Revision 0.

01-OHP.4030.STP.17TV, "Turbine-Driven Auxiliary Feed Pump Trip & Throttle Valve Operability Test," Revision 7.

02-OHP.4030.STP.101, "Main Turbine Overspeed Test," Revision 4.

02-OHP.4030.STP.019F, "Steam Generator Stop Valve Operability Test," Revision 2.

01-OHP.4030.STP.027CD, "CD Diesel Generator Operability Test (Train A)," Revision 7.

02-IHP.4030.STP.180, "SU(1) Instrumentation Checks Prior to Startup" Revision 5, August 13, 1993

The inspectors, while observing the intermediate range (IR) portion of the "SU(1) Instrumentation Checks Prior to Startup" surveillance, found that there was a different level of switch restoration verification being applied to the "Operator Selector" switch for the two IR instruments. N-35, one of the two IR instruments, required that the "Operator Selector" switch be "independently verified" and the other IR instrument, N-36, required only "verification" of the "Operator Selector" switch. The inspectors reviewed the electrical schematic and the licensee's procedure, "Plant Quality Control Program," PMI-7090, Revision 5, and determined that the "Operator Selector" switch required only a "verification" because the "level trip" switch restored the IR channel to service. An "independent verification" was required under PMI-7090 for removal and return to service of Technical Specification equipment.

The inspectors also discussed with the Instrumentation and Control (I&C) procedure writers on whether there was a procedure change request which documented the inconsistency in the "SU(1) Instrumentation Checks Prior to Startup" surveillance procedure. No procedure change request (PCR) had been written to identify the inconsistency in the verification of switch restoration steps of N-35 and N-36. However, the inspectors found that, in general, procedure discrepancies were being identified as evidenced by PCRs on other I&C procedures. The Instrumentation and Control Procedure writer stated that such discrepancies would be corrected during the next scheduled revision to the procedure.

No violations or deviations were identified.

6. Engineering & Technical Support: (37700)

The inspector monitored engineering and technical support activities at the site including any support from the corporate office. The purpose

was to assess the adequacy of these functions in contributing to other functions such as operations, maintenance, testing, training, fire protection, and configuration management.

a. Starting Air Compressors:

Over the past year the licensee has been installing new Emergency Diesel Generator (EDG) starting air compressors due to parts availability and aging concerns with the existing compressors. The compressors, even though not safety-related, maintain adequate pressure in the starting air receivers for EDG operability. Each EDG has two compressors, each supplying a separate air receiver, for a total of eight between the two units. Currently, five of the eight have been replaced with new compressors.

On November 28, 1994, the licensee tagged out the Unit 1 CD-1 compressor for replacement. The associated CD-2 compressor (previously replaced) was cross-tied to supply both air receivers. Approximately 6 hours later, air receiver pressure dropped below the alarm setpoint of 200 psig, and an operator was dispatched to investigate the alarm. The operator found the CD-2 compressor had tripped on thermal overload (TOL). The TOL was reset, and the compressor restarted. The licensee decided to return the CD-1 compressor to service pending investigation into the CD-2 failure. On December 4, 1994, a similar situation occurred following tag-out of the Unit 1 EDG AB "AB-1" compressor for replacement.

The licensee's investigation determined that the failure of the AB-2 and CD-2 compressors to maintain air receiver pressure was caused by damage to the high pressure discharge valves on the compressors. The cause was a set screw that did not meet hardness specifications which resulted in valve damage after limited service. The end result was air leakage back to the low pressure cylinder, and an inability of the compressor to adequately supply the air receivers.

The licensee has scheduled replacement of the set screws with ones that have the proper hardness. Any associated valve damage will be repaired at the same time. The set screws will be replaced on the remaining compressors prior to installment.

b. Nozzle Weld Inspection (73753)

In September 1991, a leak from a peripheral Control Rod Drive Mechanism (CRDM) nozzle occurred during a 10-year hydrotest at a French pressurized water reactor (PWR). Visual examination revealed that the leaking crack had an axial orientation and was at the elevation corresponding to the lowest portion of the partial penetration weld attaching the nozzle to the inside surface of the reactor vessel head. Additional inspection with eddy current and ultrasonic examinations and a dry penetrant test, revealed several axial cracks on the inside surface. Destructive

testing of the damaged nozzle material revealed that the through-wall crack was initiated on the inside surface at the counterbore. The crack also penetrated the weld metal (alloy 182). Since the detection of the first cracking of the CRDM nozzle, approximately 1850 nozzles were examined at 37 overseas plants, and 59 nozzles were found to have cracks. The nozzle wall beyond the attachment weld constitutes the primary pressure boundary. Any cracking in this pressure boundary or in the weld is a potential safety concern.

The licensee was one of the first to inspect the CRDM nozzles in the United States. The examination consisted of a remote automated eddy current examination for detection of cracking and a remote automated ultrasonic examination to size the depth of the flaws. The process utilized was essentially the same methodology used for the foreign reactor inspections with some enhancements. The examination procedure and examiners were qualified by full performance demonstration on CRDM nozzle mockups with manufactured flaws deposited in the nozzles. The flaws were installed and mapped by Electric Power Research Institute (EPRI). The qualification of the examination was performed at Westinghouse Waltz Mill facility where a full sized reactor vessel closure head was used to demonstrate the remote delivery tool and positioner capability. EPRI supplied the CRDM nozzle mockups for the examination qualification.

The examination tool was designed so that the CRDM nozzle thermal sleeves were not required to be removed to perform the examination. The EPRI mockups were representative of the CRDM nozzle and reactor vessel head configuration. EPRI maintained the flaw locations and sizes confidential to evaluate the effectiveness of the performance demonstration examination. The examination procedure and examiners successfully demonstrated the ability to detect and size the flaws implanted in the EPRI mockups.

The examination was performed on the Unit 1 reactor vessel head CRDM nozzle penetrations. 71 of 78 penetrations were examined using the eddy current detection procedure. The inspection surface area extended 2 inches above and below the penetration weld. One outer periphery CRDM nozzle with no thermal sleeve had axial indications that were identified below the penetration attachment weld, a non a pressure boundary area. This area was ultrasonically examined and the indications were sized with the special Time-of-Flight Diffraction (TODF) ultrasonic examination (UT) technique. The indications maximum dimensions were 45 millimeters axially with 6.8 millimeters depth.

Inspectors observed the examination performance demonstration for the eddy current detection examination at WEC Waltz Mill facility and the examination of the DC Cook Unit 2 reactor vessel head CRDM nozzle weld inspections. The examination was performed utilizing

a multi-frequency eddy current method in the absolute mode to detect any internal surface defect. The NRC inspector verified the calibration of the ET inspection process, reviewed the inspection data and ET procedure, and interviewed the ET inspectors and data analyst.

The ET inspectors were knowledgeable of the inspection process through field experience in the European inspections and the EPRI qualification, the technology has been proven to be reliable and accurate in detection and sizing of CRDM nozzle cracking.

The indications identified by ET were sized utilizing the UT-TODF. The inspector observed and reviewed the UT data and concurred with the reported inspection results. The licensee reported the results to the Office of Nuclear Reactor Regulation (NRR). The licensee's assessment of the crack indications demonstrated a conservative safety margin for one 18-month cycle of operation and another inspection will be performed during the next outage with appropriate corrective actions to be determined at that time. NRR approved the restart, and is in the process of issuing a detailed safety evaluation of the licensee's assessment.

The inspectors concluded that the licensee demonstrated a positive commitment to safety by voluntarily performing this inspection, as there was no requirement by the ASME Code Section XI, or the NRC to examine these welds.

No violations or deviations were identified.

7. Inspection Follow-up Items:

Inspection follow-up items are matters which have been discussed with the licensee involving action on the part of the NRC or the licensee or both. Inspection follow-up item disclosed during the inspection is discussed in paragraphs 5.a.3).

8. 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 5.b.

9. Exit Interview: (30703)

The inspectors met with the licensee representatives denoted in paragraph 1 at the conclusion of the inspection on December 19, 1994.

The inspectors summarized the scope and results of the inspection and discussed the likely content of this inspection report. The licensee acknowledged the information and did not indicate that any information disclosed during the inspection could be considered proprietary in nature.