U.S. NUCLEAR REGULATORY COMMISSION

REGION III

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Licensee:	Indiana Michigan Power Company
Facility:	Donald C. Cook Nuclear Generating Plant
Location:	1 Cook Place Bridgman, MI 49106
Dates:	February 15, 1997 - March 29, 1997
Inspectors:	B. L. Bartlett, Senior Resident Inspector B. J. Fuller, Resident Inspector J. D. Maynen, Resident Inspector
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Executive Summary

D. C. Cook Units 1 and 2
NRC Inspection Report 50-315/97004, 50-316/97004

This inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a 6-week period of resident inspection and includes the follow-up to issues identified during previous inspection reports.

Operations

- Licensed operators failed to include all control room instrumentation in their routine scans of the control room panels. This led to three of four over power recorder pens being inoperable for four to seven days until identified by the NRC inspectors. In addition, the operating crews and I&C were aware of the poor operating history of the recorder pens yet action was not taken until prompted by the NRC inspectors. The failure to have chart recorders capable of recording overpower transients was a deviation from a commitment in the UFSAR. Section O1.2

- The Unit 1 down power and shutdown to enter the Unit 1 refueling outage was performed in a professional and appropriate manner. Effective command and control was maintained by the operating staff. Section O1.3

- An inadequate procedure was used during a reactor trip recovery activity and resulted in an inadvertent ESF actuation when the TDAFP was reset too close to the SG low low level setpoint. This was considered an example of a violation.

- The failure to implement adequate corrective actions to prevent the reoccurrence of a failure of a Taylor Mod 30 controller was an example of a violation. Section O1.4

- The licensee took immediate, comprehensive corrective action to restore and maintain the flowpath for water to reach the recirculation sump. The licensee's safety assessment had shown that in the event of a loss of coolant accident while shutdown, the sump was important to maintaining the unit in a safe shutdown condition. Section O1.5

- The startup following the Unit 2 unplanned reactor trip proceeded well. The inspectors noted effective command and control was maintained, and that communications were excellent during the pre-job briefing and during the approach to criticality. In addition, there was a low, manageable number of personnel present and control room distractions were minimized. Section O1.6

Maintenance

- Plastic shields installed in the control room in order to keep snow out of the backs of the control panels were not recognized as a temporary modification. Even though the licensee has made significant progress in the improvement of temporary modifications, unrecognized temporary modifications may remain installed in the plant. The installation of a temporary modification without the proper evaluations was a violation. Section M2.1

- A poorly worded TS surveillance requirement concerning the turbine driven auxiliary feedwater pump (TDAFWP) was identified by the inspectors. The licensee recognized these problems and agreed to initiate the appropriate TS change requests. Section M3.1

- The inspectors noted that the licensee's procedure for testing the containment evacuation alarm was inadequate, the coverage of the horns inside containment was inadequate, and that when informed of an inoperable horn that the Unit Supervisor failed to initiate an action request. In addition, the procedures covering use of the containment evacuation alarm were inconsistent in requiring a plant announcement. Section M3.2

- The licensee failed to adequately remove the spiral wound gasket material from the RHR system following the second spiral wound gasket failure on 1-IRV-311, identified on January 31, 1996, resulting in this material entering several components in the RHR system and also entering the reactor coolant system. This was considered a violation. The failure to address ECCS check valve operability is an unresolved item. Section M4.1

- The failure to install the cage spacers after refurbishing 1-QRV-114 and 1-NRV-163 were two cases of contractor personnel failing to follow procedure. These were two examples of a violation. Section M4.2

- The technicians working within the FMEZ next to the refueling cavity did not consistently apply the practices established to keep foreign material out of open systems. The failure to follow FME procedures was a violation. Section M4.3

Engineering

- The licensee conservatively expanded the scope of their inspection to Unit 2 after identifying cracks in Unit 1 flood-up tubes. Following the identification of flaws in two Unit 2 flood up tubes, the licensee declared the affected equipment inoperable and made a required report to the NRC.

  The environmental qualification of equipment associated with cracked flood-up tubes was an unresolved issue. A violation was identified when the licensee failed to make a timely report to the NRC concerning equipment that had been identified as inoperable due to the cracked flood up tubes in Unit 1. Section E2.1

- The inspectors raised questions concerning the licensee's testing configuration for the control room emergency ventilation system. After promptly performing a test to verify there were no operability concerns the licensee initiated a procedure change request in order to better control the test configuration. Section E3.1

Plant Support

- Routine observations were made by inspectors with no discrepancies noted.

Report Details

Summary of Plant Status

Unit 1 main transformer temperature limitations forced operation of the Unit at 92 percent to 94.7 percent power during the beginning of the inspection period. On February 15, 1997, power was reduced as part of the "coastdown" into the refueling outage. On February 27, 1997, reactor power was stabilized at 51% in order to perform steam generator code safety valve testing. On March 1, 1997, the Unit was shutdown and entered the refueling outage.

Unit 2 was at full power at the beginning of the inspection period. On February 8, 1997, power was reduced to 55 percent in order to perform corrective maintenance on the East Main Feedpump. The Unit was returned to full power on February 17, 1997. On March 11, 1997, the Unit tripped from full power when a feedwater regulating valve failed closed. The valve failed closed when its controller failed. The Unit was returned to full power on March 18, 1997, following repairs to various controllers and the replacement of a circulating water pump discharge valve.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. The conduct of operational activity that was observed was generally good. Specific events and noteworthy observations are detailed in the sections below.

O1.2 Inoperable Control Room Overpower Chart Recorders (Unit 1)

a. Inspection Scope (71707)

During routine control room observations the inspectors identified that three of four nuclear instrumentation power range recorders were malfunctioning. The inspectors performed routine follow-up to the licensed operators' failure to identify the malfunctioning recorders.

b. Observations and Findings

During routine control room observations on February 25, 1997, the inspectors observed that the recorder pens recording power level for nuclear instrumentation power range channels N-41, N-42, and N-43 were not accurate. The four nuclear instruments were recorded on two chart recorders. Each of the two chart recorders had a range of from 0 percent to 200 percent in order to record any large scale overpower excursions. The inspectors observed that on the two chart recorders the pens were showing the values given below:

Nuclear Instrument Channel	Chart Recorder Reading	Reactor Power Level
N-41 Recorder 1-SG-13	92%	78%
N-42 Recorder 1-SG-14	86%	78%
N-43 Recorder 1-SG-13	92%	78%
N-44 Recorder 1-SG-14	78%	78%

The inspectors questioned the two reactor operators (ROs) and determined they were not aware that the three overpower nuclear instruments were showing incorrect values.

Unit 1 reactor power was being reduced at a rate of 2 percent per day as part of the end of cycle power reduction. This meant that the meters stuck on 92 percent had been inoperable for approximately one week and that the meter stuck on 86 percent had been inoperable for approximately four days.

Interviews with randomly selected ROs revealed that the chart recorders had a history of sticking. Chart recorder 1-SG-13 had an action request (AR) written against it since December 2, 1996, saying that the pens were sticking. The AR was written by I&C personnel following a surveillance test.

Following the inspectors' identification of the sticking recorder pens, the RO opened the recorder covers and reset them to the correct power level. In addition, the RO wrote an AR for the stuck recorder that did not already have an existing AR.

UFSAR Chapter 7, Instrumentation and Control, section 7.4.1 stated, "The power range channels are capable of recording overpower excursions up to 200 percent of full power." Even though there were other meters which monitored overpower transients up to 200 percent of full power, these were the only pens which would record postulated overpower transients.

The inspectors determined that:

- The reactor operators, unit supervisors, and shift supervisors were not including these recorders in their scans of the control boards.

- The chart recorders had a history of operability problems. Licensee personnel informed the inspectors that since June of 1991, the failure rate was such that the percent pen unavailability average was 14.9 percent. The

inoperability of the recorders was a deviation from the licensee's UFSAR commitment to have chart recorders capable of recording overpower transients (50-315/97004-05 (DRP)).

- The low reliability/availability rate combined with the lack of use for operations or surveillances had apparently led to the licensed operators giving these pens a negligible "scan rate."

- No operations or surveillance procedures used these chart recorders. When changing power levels the operators used recorders/meters with a fine scale, so these recorders were not used.

Corrective actions by the licensee following the identification of this issue by the inspectors consisted of:

- Informing the operating crews to include these chart recorders in their scans of the control room instrumentation.

- Instructing the operating crews to scan the entire control room and to ensure that all degraded instrumentation was identified and corrected in a timely manner.

- Performing a modification to remove these chart recorders and to record these channels on other chart recorders. This modification had been in the planning stages prior to the inspectors' concerns being identified. This modification was in progress on Unit 1 at the end of the report period and was being planned for Unit 2 during its next refueling outage.

- Performing a one time special review of control room instrumentation to ensure that all degraded instruments were identified and were scheduled to be repaired on a timely basis.

c. <u>Conclusions</u>

Licensed operators failed to include all control room instrumentation in their routine scans of the control room panels. This led to three of four over power recorder pens being inoperable for four to seven days until identified by the NRC inspectors. In addition, the operating crews and I&C were aware of the poor operating history of the recorder pens yet action was not taken until prompted by the NRC inspectors. The failure to have chart recorders capable of recording overpower transients was a deviation from a commitment in the UFSAR.

O1.3 Shutdown for Refueling (Unit 1)

a. Inspection Scope (71707 and 60710)

The inspectors observed licensee personnel perform the shutdown of Unit 1. The shutdown was performed to enter the Spring 1997 refueling outage. Licensee procedures observed included:

- 01-OHP-4030.STP.026 — Auxiliary Power Transfer Test Surveillance Procedure, Revision 7
- 01-OHP 4021.055.004 — Removing a Main Feedpump and Feedpump Turbine From Service, Revision 6
- 01-OHP 4021.001.003 — Power Reduction, Revision 12
- ** 01-OHP 4021.002.005 — RCS Draining, Revision 20, to half loop conditions
- ** 01-OHP 4021.001.004 — Plant Shutdown from Hot Standby to Cold Shutdown, Revision 29

b. Observations and Findings

On the evening of March 1, 1997, the inspectors observed the licensee perform a routine shutdown from power to enter a refueling outage. The inspectors observed that effective command and control was maintained by the Unit Supervisor and the Shift Supervisor. This command and control was challenged; however, by the relatively large number of personnel present to support the shutdown. At various times there were between 25 and 35 operators, I&C technicians, managers, and other personnel in the Unit 1 control room.

c. Conclusions

The Unit 1 down power and shutdown to enter the Unit 1 refueling outage was performed in a professional and appropriate manner. Effective command and control was maintained by the operating staff.

O1.4 Reactor Trip (Unit 2)

a. Inspection Scope (71707)

On March 11, 1997, Unit 2 tripped from 100 percent power as a result of a failed feed regulating valve controller. This caused a low level in its associated steam generator (S/G). All equipment functioned as expected with the following exceptions: the main turbine turning gear motor failed, a main feedwater pump

turning gear failed to engage, and the turbine driven auxiliary feedwater pump (TDAFWP) experienced an inadvertent ESF actuation. The inspectors reviewed the licensee's response to the trip.

b. Observations and Findings

The Unit 2 reactor trip was initiated by low steam generator level coincident with a steam flow/feed flow mismatch, as a result of failure of the controller for feed regulating valve, 1-FRV-210.

The Balance of Plant (BOP) operator, in preparation for a surveillance on steam generator number 1 level instrument, attempted to place the controller in manual mode. The controller face went blank when he touched the face plate. The failure of the controller resulted in the feed regulating valve going shut.

The controller, a Taylor Mod 30, was known to be susceptible to electrostatic discharge effects (see NRC inspection report 50-315/316-96004 (DRP)). Beginning in March 1996, problems with electrostatic discharge sensitivity of Taylor Mod 30 controllers were identified as a result of a controller failure leading to a Unit 1 reactor trip. Four other controllers in Units 1 and 2 exhibited similar sensitivity. Failure of a controller in Unit 1 caused a halt in unit power escalation in June 1996. Determination of a root cause was undertaken. Corrective actions were enacted to prevent recurrence of the controller failure. The corrective actions included: increasing control room humidity, instructing operators to ground themselves prior to operation of Taylor Mod 30 controllers, installation of static grounding mats, verification that control room carpeting was anti-static, installation of ground wires and verifying connection of static drain clips in the controllers. Some controllers, including the controller for 1-FRV-210, had not yet been modified to the optimal configuration, because of the operating status of the unit.

The BOP operator had taken the required precautions (grounding himself against the control panel, and standing on the static grounding mat), but the controller exhibited the characteristic electrostatic discharge failure. A violation of Criteria XVI of 10 CFR Part 50 Appendix B was identified in that inadequate corrective actions to prevent the reoccurrence of controller failures were taken by the licensee (50-316/97004-02a (DRP)).

During the post-trip shutdown, the licensee replaced the controller with a controller modified to be less susceptible to the effects of electrostatic discharge. Additional corrective actions included requiring operators to wear static control heel grounding assemblies on their shoes, procurement of low static electricity chairs for the control room crew, and directing the operators to ground themselves to bare metal prior to touching the controller faceplate.

The operators secured the TDAFWP, as allowed by 02-OHP 4023.ES-0.1, Reactor Trip Response, to minimize the cooldown of the reactor coolant system. Steam generator (S/G) level oscillations near the low-low level TDAFWP start setpoint generated a second start signal as S/G levels were being increased during post-trip

recovery actions. Procedure ES-0.1 did not contain guidance for the operators concerning where to maintain S/G levels in order to avoid a restart of the TDAFWP. The licensee considered this to be an operator knowledge item, which was covered during operator training. The quality of the procedure ES-0.1 was not of a type appropriate to the level of knowledge of the operator. This was a violation of 10 CFR Part 50, Appendix B, Criterion V (50-315/316/97004-01a (DRP)).

After the main turbine tripped, the motor for the main turbine turning gear failed. The cause for the failure was worn/damaged bearings which allowed the rotor to drop down in contact with the stator causing arcing and smoke. The motor was replaced and the turbine was placed on the turning gear.

c. Conclusions

An inadequate procedure was used during a reactor trip recovery activity and resulted in an inadvertent ESF actuation when the TDAFP was reset too close to the SG low low level setpoint. This was considered a violation.

The failure to implement adequate corrective actions to prevent the recurrence of a failure of a Taylor Mod 30 controller was a violation.

O1.5 Control of Transient Material in Containment (Unit 1)

a. Inspection Scope (71707)

On March 11, 1997, the licensee stopped fuel movement operations due to the lack of a flow path to the emergency core cooling system (ECCS) recirculation sump in lower containment.

The inspectors performed routine followup to the licensee's resolution of the issue as the inspectors had identified the debris at about the same time as licensee management. In addition to the followup, the inspectors reviewed licensee procedure, OHI-4100, Outage Technical Advisor Risk Assessment, Revision 0.

b. Observations and Findings

During a routine containment tour, the inspectors identified a large accumulation of bagged material in the area directly in front of the grates at the entrance to the ECCS recirculation sump in lower containment. The materials consisted of scaffolding, S/G eddy current inspection equipment and a large amount of bagged insulation removed in preparation for S/G inspections. The licensee had independently identified that transient material had been allowed to accumulate and was in the process of taking action to remove the material.

OHI-4100 Attachment 3, Inventory - Mode 6B, required maintaining one loop of residual heat removal (RHR) operable with a flowpath from the reactor coolant system (RCS) and recirculation sump. As the material in front of the recirculation sump screens could block water from reaching the sump in the event of a refueling

cavity seal failure, the licensee conservatively declared the recirculation sump inoperable. With the sump inoperable, the licensee entered a red path for shutdown risk, which by licensee procedures required immediate compensatory action.

Core alterations were suspended in accordance with OHI-4100 while actions were taken to restore the flowpath. The actions included a concentrated cleanup effort which involved restowing and securing items that would float. Plant Manager's Standing Order (PMSO) 179, Transient Materials in Containment While the Unit is Shutdown, Revision 0, was issued to provide guidance for control of transient materials in containment during reactor shutdown conditions. Core alterations were restarted after completion of the cleanup.

c. Conclusions

The licensee took immediate, comprehensive corrective action to restore and maintain the flowpath for water to reach the recirculation sump. The licensee's safety assessment had shown that in the event of a loss of coolant accident while shutdown, the sump was important to maintaining the unit in a safe shutdown condition.

O1.6 Inspector Observations of Portions of the Licensee's Return to Power (Unit 2)

a. Inspection Scope (71707)

On March 16, 1997, the licensee started up the Unit 2 reactor following the reactor trip. The inspectors observed all or part of the following activities and procedures:

- **02-OHP 4021.001.002 — Reactor Start-Up, Revision 18
- **02-OHP 4021.001.006 — Power Escalation, Revision 15
- **02-OHP 4021.050.001 — Turbine Generator Normal Startup and Operation, Revision 9
- 02-OHP 4021.013.005 — Visual Audio Count Rate Channel (NIS), Revision 4
- 02-OHP 4024.210 — Annunciator #210 Response: Flux Rod, Revision 6
- **12 EHP 6040 PER.370 — Estimation of Critical Position, Revision 1
- Technical Data Book

b. Observations and Findings

The inspectors observed that licensed reactor operators complied with their procedures and maintained effective command and control during the startup. The

inspectors also observed that the operators were attentive during their pre-job brief before the pull to criticality. Comments made to the operators by a member of operations management concerning repeat backs resulted in significant increase in the use of three point communications. During a review of the startup procedures in use, the inspectors noted that alarm response procedure 02-OHP 4024.210 Revision 6, CS-2, Drop 29, listed a deleted technical specification as a reference; however, this did not affect the actions required by the procedure. The unit supervisor was notified of the discrepancy, and the procedure was revised.

c. Conclusions

The startup following the Unit 2 unplanned reactor trip proceeded well. The inspectors noted effective command and control was maintained, communications were excellent during the pre-job briefing and during the approach to criticality. In addition, there was a low, manageable number of personnel present and control room distractions were minimized.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62703 and 61726)

Portions of the following maintenance job orders, action requests, and surveillance activities were observed or reviewed by the inspectors:

- 01-OHP 4030.STP.037 — Refueling Surveillance, Revision 14
- 01-OHP-4030.STP.026 — Auxiliary Power Transfer Test Surveillance Procedure, Revision 7
- **12-EHP 4030.STP.229 — Control Room Emergency Ventilation System, Revision 2
- ** 01-EHP 4030 STP.217B — Diesel Generator 1 AB Load Sequencing and ESF Testing, Revision 3
- C0040106 — Fisher V100 Vee-Ball Control Valve Maintenance, on 1-IRV-310, using ** 12 MHP 5021.001.102
- R0022763 — Foreign Material Exclusion (FME), inspection of Unit 1 Refueling Water Storage Tank using 12 PMP 2220.001.001

- R0049426 — Pressurizer Pressure Transmitter Calibration, using ** 01 IHP 6030.IMP.363
- R0049473 — Leak test of valve 1-ICM-129, using ** 12 EHP 4030.STP.242
- R0051820 — Darling S-350W-SC Swing Check Valve Maintenance, on 1-SI-166-02 using ** 12 MHP 5021.001.116

b. Observations and Findings

The inspectors found the work performed under these activities to be generally of good quality with procedures present and in use. Comments for specific work activities are discussed in further detail below.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Unauthorized Temporary Modification Installed in the Control Room Emergency Ventilation System (Both Units)

a. Inspection Scope (62703)

On March 6, 1997, at 3:30 a.m., licensee personnel identified a plexiglass rain/snow cover located just below the return air duct to the Unit 2 control room. This cover had the potential to affect the operability of the Unit 2 control room emergency ventilation system (CREVS). Both trains of the Unit 2 CREVS were declared inoperable and TS 3.0.3 was entered. Shortly afterwards the cover was removed and TS 3.0.3 was exited. The inspectors performed follow up to the event. Licensee documents reviewed, included:

- Condition Report 97-0590
- Plant Managers Procedure, PMP 5020.RTM.001, Revision 0, Restraint of Transient Material.
- UFSAR 9.10, Control Room Ventilation System
- Drawing OP-2-5149-29, Flow Diagram Control Room Ventilation Unit No. 2
- PMP 5040.MOD.001, Revision 5, Temporary Modification
- Action Requests C0034756, C0034755, R064539, R064538

b. Observations and Findings

During the routine testing of the Unit 1 engineered safety features actuation system, the CREVS for both Unit 1 and Unit 2 would actuate as designed. During one of the Unit 1 tests, the Unit 2 control room operators observed a plexiglass rain/snow cover causing pressure fluctuations in the Unit 2 control room. The operators observed the cover moving up, partially blocking the return air duct and then falling away.

As blockage of the return air duct could interfere with the proper operation of the CREVS, the operators declared one train of CREVS inoperable. Shortly thereafter, discussions with a licensing engineer determined that since the duct was common to both trains of CREVS, calling both trains of CREVS inoperable would be appropriate and entry should be made into TS 3.0.3. The need to enter TS 3.0.3 was recognized at 4:10 a.m., the plastic shields were removed, and TS 3.0.3 was exited at 4:35 a.m.

As required by 10 CFR 50.72 the licensee made a one hour report to the NRC for the discovery of a condition outside the design basis for Unit 2. A plastic shield was also installed under the Unit 1 return air duct, however it had been restrained differently than the Unit 2 plastic shield. Thus, the Unit 1 plastic shield did not interfere with the proper operation of the Unit 1 CREVS.

The licensee's investigation showed that the shields were installed to prevent snow from entering the backs of the control room panels. At the time of installation, some licensee personnel questioned whether the plastic shields were temporary modifications. A review resulted in a licensee determination that the plastic shields were not temporary modifications but were housekeeping items. This determination was in error as the plastic shields could interfere with the proper operation of the CREVS.

Even though the plastic shields were not deemed to be temporary modifications, the personnel who wrote the work instructions recognized the need to restrain the shields. Accordingly, the job orders contained work instructions to fasten the plastic shields in a manner to prevent them from being sucked up against the inlet ducts. This was done for Unit 1 however, the Unit 2 plastic shield was not properly restrained.

This licensee change to the facility as described in the UFSAR without following plant procedures governing temporary modifications and without a required written safety evaluation which provides the bases for the determination that the change does not involve an unreviewed safety question is a violation of 10 CFR Part 50.59 (50-315/316-97004-04(DRP)).

Temporary modifications have been the subject of previous NRC inspection reports. Reports 50-315/316-96002 and 96014 discussed examples of poor safety evaluations. Report 50-315/316-96011 discussed a violation for implementing a change to the facility but not recognizing that it was a temporary modification. In

response to the issues discussed above, the licensee has spent considerable effort in training personnel in the understanding of and the proper use of temporary modifications. Since these corrective actions have been implemented, the inspectors have noted a marked increase in the quality and use of temporary modifications.

c. <u>Conclusions</u>

Plastic shields installed in the control room in order to keep snow out of the backs of the control panels were not recognized as a temporary modification. Even though the licensee has made significant progress in the improvement of temporary modifications, unrecognized temporary modifications may remain installed in the plant. The installation of a temporary modification without the proper evaluations was a violation.

M3 Maintenance Procedures and Documentation

M3.1 <u>Questions Concerning Surveillance Tests of the Turbine Driven Auxiliary Feedwater Pump (TDAFWP) (Both Units)</u>

a. <u>Inspection Scope (62703)</u>

During a routine review of licensee surveillance tests the inspectors questioned whether the TDAFWPs were being tested in accordance with technical specification requirements. The inspectors reviewed the licensing basis of the TDAFWPs, reviewed completed surveillance tests, interviewed licensee personnel, and held telephone conferences with NRR personnel in order to evaluate the licensee's surveillance procedures for verifying TDAFWP operability.

Documents reviewed by the inspectors included:

- Design Basis Document DB-12-AFW, Auxiliary Feedwater System Design Basis Document
- **01(2)-OHP 4030.STP.017T, Turbine Driven Auxiliary Feedwater System Test, Revisions 9, 10, and 11
- Licensee Technical Specification Clarification 61, Auxiliary Feedwater System Surveillance Requirements, dated April 21, 1994
- Technical Specification Amendments 203 to license number DPR-58 and 188 to license number DPR-74
- UFSAR Chapters 14.1, 14.2, 14.3, and 10.5
- Licensee letter AEP:NRC:0969AM, Donald C. Cook Nuclear Plant - Unit 1 Pump Inservice Test Program

b. Observations and Findings

Technical Specification (TS) surveillance requirement 4.7.1.2.b stated, in part, "Each auxiliary feedwater pump shall be demonstrated OPERABLE when tested pursuant to Specification 4.0.5 by: . . . Verifying that the turbine driven auxiliary feedwater pumps' developed head at the test flow point is greater than or equal to the required developed head when the secondary steam supply pressure is greater than 310 psig. The provisions of Specification 4.0.4 are not applicable for entry into MODE 3."

The licensee routinely performed the surveillance test at a secondary side pressure of between 500 psig and 900 psig. The inspector's concerns centered on the question of whether the licensee was required to perform the surveillance test at just greater than 310 psig (e.g., 311 psig).

The licensee informed the inspectors that their interpretation of the TS surveillance requirement differed in that they thought the test could be performed at any pressure greater than 310 psig. Since 500 to 900 psig was greater than 310 psig, the licensee thought that the test was being properly performed. When questioned as to the basis for greater than 310 psig the licensee performed a review of the license basis and determined that there appeared to be no technical justification for the specific value of 310 psig. The licensee also stated that in 1994, they had attempted to run the surveillance at 310 psig, but the pump was not capable of full rated speed, flow, or discharge pressure at such a low secondary side pressure.

The TS surveillance requirement had been changed on October 17, 1995, by amendment 203 to the Unit 1 TSs. The inspectors review of the previous TS surveillance requirement identified that it did require a pump discharge pressure and flow rate that the TDAFWP was incapable of while at a secondary side pressure of greater than 310 psig. The licensee disagreed with the inspector's conclusions and stated that the TDAFWP was never expected to perform at a high discharge pressure and flow rate at low secondary side pressures.

NRC internal discussions confirmed the inspectors' finding that the previous TS requirements were clear and that the TDAFWP had been required to perform at the higher rated discharge pressure and flows. However, the inspectors review of the design basis and licensing basis of the TDAFWP confirmed the licensee's statement that the TDAFWPs were not taken credit for in any accident analysis at the secondary side pressure of 310 psig. Therefore, even though the surveillance procedures did not meet the previous TS surveillance requirement they did comply with the present TS surveillance requirements and at all times had complied with the licensing basis.

The inspectors identified several other licensee documents which appeared to show the TDAFWP was capable of high discharge pressures and flows at a low secondary side pressure. The licensee stated that these statements were in error and would be corrected.

The inspectors completed their assessment of this issue and had no operability concerns with the present surveillance requirements. The licensee stated that a TS change request would be submitted to clarify the existing surveillance requirements.

c. Conclusions

A poorly worded TS surveillance requirement concerning the turbine driven auxiliary feedwater pump (TDAFWP) was identified by the inspectors. The licensee recognized these problems and agreed to initiate the appropriate TS change requests.

M4 Maintenance Staff Knowledge and Performance

M4.1 Spiral Wound Gasket Material in the Reactor Coolant System and the Reactor Vessel (Unit 1)

a. Inspection Scope (62703)

On March 12, 1997, during core off-load, the licensee found spiral wound gasket material on the bottom nozzles of three fuel assemblies. Additional material was found on the lower core plate. During inspections of the emergency core cooling systems (ECCS), spiral wound gasket material was found in accumulator discharge check valves 1-SI-166-2 and 1-SI-166-3. The loop 4 safety injection (SI) and residual heat removal (RHR) cold leg check valve, 1-SI-161-L4, also contained a piece of spiral wound gasket material. The inspectors followed the licensee's investigation into the possible sources of the material, the scope of the problem, and the corrective actions. In addition, the following documents were reviewed:

- C0040106 ** 12 MHP 5021.001.102, Fisher V100 Vee-Ball Control Valve Maintenance, Revision 1, on 1-IRV-310
- R0022763 12 PMP 2220.001.001, Foreign Material Exclusion (FME), Revision 0, inspection of Unit 1 Refueling Water Storage Tank
- R0051820 ** 12 MHP 5021.001.116, Darling S-350W-SC Swing Check Valve Maintenance, Revision 1, on 1-SI-166-02
- NRC Inspection Report 50-315/316-95010
- NRC Inspection Report 50-315/316-96002

b. Observations and Findings

The licensee's investigation identified several possible sources of the spiral wound gasket material which was found in the ECCS and reactor vessel. Residual heat removal (RHR) heat exchanger outlet valves, 1-IRV-310 and 1-IRV-320, each contained two spiral wound gaskets. A similar valve, the RHR heat exchanger bypass valve, 1-IRV-311, had two earlier spiral wound gasket failures, but its gaskets were replaced with compressed fiber gaskets following the second failure. These failures were discussed in NRC Inspection Reports 50-315/316-95010 and 50-315/316-96002, respectively. Additionally, the spiral wound gaskets were found separated and missing some material on 1-QRV-114, the reactor coolant excess letdown to excess letdown heat exchanger shutoff valve, and 1-NRV-163, the pressurizer spray control valve.

Both 1-IRV-310 and 1-IRV-320 were inspected, and approximately 21 total feet of spiral wound gasket material was missing from these two valves. Additionally, the licensee speculated that some spiral wound gasket material may have remained in the RHR system from the earlier gasket failures of 1-IRV-311. The loop 4 SI and RHR cold leg check valve, 1-SI-161-L4, failed an "as found" leak rate test in Mode 4. Subsequent inspection of this valve and two other check valves, 1-SI-166-2 and 1-SI-166-3, accumulator discharge check valves, revealed spiral wound gasket debris in all three valves. Additional inspections for spiral wound gasket material were performed on the refueling water storage tank (RWST), the ECCS suction header from the RWST, and the lower reactor vessel. The lower reactor vessel was found to contain some spiral wound gasket material, but no spiral wound gasket material was found in either the RWST or the ECCS suction header. The failure to adequately remove the spiral wound gasket material from the RHR system and RCS was a significant condition adverse to quality in which corrective action was not taken to prevent recurrence. This failure was a violation of 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Action (50-315/316/97004-02b (DRP)).

The licensee concluded that any gasket material from 1-QRV-114 was captured in the excess letdown heat exchanger and did not enter the RCS. The spiral wound gasket material missing from 1-NRV-163 was determined to have remained either in the pressurizer spray line or in the pressurizer due to low flow rates and had not entered the reactor vessel. The gasket failures of 1-QRV-114 and 1-NRV-163 are discussed in section M4.2.

An operability evaluation performed after the second failure of the gasket on 1-IRV-311 determined that the ECCS systems remained operable, even with some material left in the system. This operability evaluation discussed pump operability and fuel damage potential from spiral wound gasket material; however, it did not address ECCS valve operability. The failure to address ECCS valve operability is an Unresolved Item (50-315/97004-06 (DRP)) pending the results of the ECCS testing and evaluation of check valve operability.

The licensee conducted flushes of the RHR and connected ECCS systems in order to dislodge any spiral wound gasket material in the piping and collect it in the defueled reactor vessel for removal. The licensee planned to perform an additional test of the ECCS pressure isolation valves prior to returning Unit 1 to full power.

c. Conclusions

The licensee failed to adequately remove the spiral wound gasket material from the RHR system following the second spiral wound gasket failure on 1-IRV-311,

identified on January 31, 1996, resulting in this material entering several components in the RHR system and also entering the reactor coolant system. This failure constituted a violation.

The failure to address check valve operability is an unresolved item pending the results of the ECCS testing and evaluation of check valve operability.

M4.2 Missing Cage Spacer on 1-NRV-163 and 1-QRV-114 (Unit 1)

a. Inspection Scope (62703)

On March 11, 1997, during refurbishment of valve 1-QRV-114, the reactor coolant excess letdown to excess letdown heat exchanger shutoff valve, the spiral wound cage gasket was found to be separated and broken in pieces. On March 13, 1997, during disassembly for corrective maintenance on valve 1-NRV-163, the pressurizer spray control valve, the spiral wound cage gasket was found to be damaged with some material missing. Both valves were found to be missing cage spacers, an internal valve part designed, in part, to compress the cage gasket. The evaluation of the missing gasket material is discussed above in section M4.1. The inspectors followed the licensee's corrective actions and reviewed the following documents:

- **12 MHP 5021.001.126 — Copes-Vulcan Bellows Seal Control Valve Maintenance, Revision 1
- **12 MHP 5021.001.057 — Copes-Vulcan Isolation Valve Maintenance, Revision 1
- R0020879 — Refurbishment of 1-NRV-163 during the Unit 1 1995 refueling outage
- R0020974 — Refurbishment of 1-QRV-114 during the Unit 1 1994 refueling outage

b. Observations and Findings

The licensee's investigation into the missing cage spacer identified previous refurbishments in 1994 for 1-QRV-114 and in 1995 for 1-NRV-163 as the most likely times when the cage spacer was not installed. The licensee stated that the missing cage spacer was the most likely reason that 1-NRV-163 was inoperable during all of the most recent fuel cycle. The licensee also stated that the missing cage spacer on 1-QRV-114 was not noticed earlier because the valve was infrequently operated.

Step 7.3.2 of **12 MHP 5021.001.126, Copes-Vulcan Bellows Seal Control Valve Maintenance, Revision 1, required that the cage spacer be installed during valve reassembly. Step 6.3.2 of ** 12 MHP 5021.001.057, Copes-Vulcan Isolation Valve Maintenance, also required that the cage spacer be installed during valve

reassembly. Job Order Activity (JOA) R0020879 required the use of ** 12 MHP 5021.001.126, and JOA R0020974 required the use of **12 MHP 5021.001.057.

In both cases, a valve contractor performed the maintenance work. The licensee speculated that the contract workers may not have been familiar with Copes-Vulcan valves. The failure to install the cage spacers after refurbishing 1-QRV-114 and 1-NRV-163 were two cases of contractor personnel failing to follow procedure. The failure to follow procedure ** 12 MHP 5021.001.057 was one example of a violation (50-315/97004-01c (DRP)). The failure to follow procedure ** 12 MHP 5021.001.126 was another example of a violation (50-315/97004-01d (DRP)). For the current refueling outage, the licensee used a different valve contractor than was used during the earlier valve refurbishments.

The valves were reassembled, all of the parts were installed, and successfully tested. Two mock up Copes-Vulcan valves for training on proper disassembly and reassembly were obtained, and the licensee planned to revise the procedures to more clearly state how these valves are to be reassembled.

c. Conclusions

The failure to install the cage spacers after refurbishing 1-QRV-114 and 1-NRV-163 were two examples of contractor personnel failing to follow procedure. These failures were two examples of a violation for failure to follow procedures.

M4.3 Foreign Material Exclusion Practices (Unit 1)

a. Inspection Scope (62703)

On March 23, 1997, during core barrel former bolt work in Unit 1 containment, the inspectors observed contractor personnel working in a foreign material exclusion zone. The contractors were preparing a camera for use in machining prior to installation of a new former bolt. After the inspectors left the area, they reviewed the licensee's procedures concerning FME and developed questions concerning procedural adherence.

The inspectors reviewed licensee procedure 12 PMP 2220.001.001, Foreign Material Exclusion, Revision 0.

b. Observations and Findings

The contractor technicians prepared a camera assembly by attaching two camera modules and a light to a frame. The work was performed in the area directly adjacent to the refueling cavity near the location of the core barrel. This area had been established as a Foreign Material Exclusion Zone (FMEZ) in accordance with PMI 2220, Foreign Material Exclusion.

12 PMP 2220.001.001, Foreign Material Exclusion, step 5.2.7 required, in part, that light hand tools be secured to the person using them by a lanyard or tagline.

The technicians used tools such as open end wrenches, needle-nosed pliers and lock-wire pliers to attach and captivate the assembly. Each of the tools used had an attached lanyard to secure the tool to the person. In several instances, the inspectors observed that the person using the tool did not attach the lanyard to his arm while the tool was in use. The inspector's subsequent review of the licensee's procedures led to the questioning of this practice.

12 PMP 2220.001.001, Foreign Material Exclusion, step 5.2.8 required in part, that tools shall not be left laying loose within the FMEZ. All such tools shall be restrained in an appropriate manner to prevent their introduction into any open equipment or system. The workers used the temporary bridge over the cavity as their tool laydown area. When a tool was needed, the technician would obtain it from the laydown area. In several instances, the inspectors observed that tools were left loose on the tarp covering the work area instead of returned to the laydown area. The inspector's subsequent review of the licensee's procedures led to also questioning this practice.

Licensee senior management had performed tours of the turbine and auxiliary buildings and upper and lower containment on each shift for the entire outage. Their post-tour observations reviewed by the inspectors, repeatedly stated that workers needed to clean up their areas. Licensee management informed the inspectors that FME awareness and compliance were not at the level desired.

These failures to follow procedures were an example of a violation of Technical Specification 6.8.1 (50-315/97004-01b (DRP)).

c. <u>Conclusions</u>

The technicians working within the FMEZ next to the refueling cavity did not consistently apply the practices established to keep foreign material out of open systems. The failure to follow FME procedures was a violation.

<u>III. Engineering</u>

E1 Conduct of Engineering

During the resident inspection activities, routine observations were conducted in the areas of engineering using Inspection Procedure 37551. Engineering personnel were observed to promptly respond to plant issues and to perform good evaluations.

E2 Engineering Support of Facilities and Equipment

E2.1 <u>Damaged Flood-up Tubes Required For Environmental Qualification of Electrical Wires (Both Units)</u>

The electrical penetrations for containment are located below the calculated containment flood-up level following a loss of coolant accident (LOCA). Because safety related cables had not been qualified for submergence in water, they were contained inside stainless steel tubes which provide a barrier between the cable and the water in containment during postulated post-accident conditions.

The licensee had previously identified some moisture in a flood-up tube. As a result, the licensee had made an internal commitment to inspect about one-third of the flood-up tubes in each unit during the next three refueling outages. Inspection of flood-up tubes in Unit 1, was performed in March, 1997. The inspection revealed some tubes with moisture but also identified cracks, flaws, or arc strikes in nine tubes. These flaws would provide a pathway for water to enter the tubes following a postulated accident. A condition report was initiated and the equipment associated with these flood-up tubes was declared inoperable. Licensee personnel decided to evaluate the actual operability of Unit 1 equipment after performing an immediate inspection of Unit 2 for flawed flood-up tubes.

The licensee conservatively decided to perform an inspection of flood-up tubes in Unit 2, instead of waiting for its next scheduled refueling outage. The inspection was performed on March 23, 1997 and identified cracks in two tubes. A condition report was initiated and the equipment associated with these flood-up tubes was declared inoperable.

The power cable for containment recirculation fan 2-HV-CEQ-1 was located in one of the cracked tubes. Operability of the fan could not be guaranteed with water in the tube after a LOCA. The licensee could not determine when the cracks developed in the tube; but believed that the flaws in the tubes in both units had been present since the tubes were originally installed. This meant that the flaws had been present for many years and that the equipment had been inoperable for many years.

The licensee made a one hour notification to the NRC in accordance with 10 CFR 50.72(b)(1)(ii)(A) for Unit 2 once this condition was identified. This was due to the other train of containment recirculation fan being inoperable for maintenance periodically in the past. This meant that periodically both trains of recirculation fans were inoperable. This necessitated an entry into TS 3.0.3 due to Unit 2 being in an unanalyzed condition. However, the licensee did not also report that the inoperability of 2-HV-CEQ-1 exceeded the allowable outage time of 48 hours as specified in the action statement of Technical Specification 3.6.5.6, which also would have placed the Unit in TS 3.0.3. This failure to report under this additional reporting requirement was minor in nature as the condition had already been reported.

The inspectors also identified a violation of 10 CFR 50.72(b)(2)(i) reportability requirements for Unit 1. The licensee had the same information available for Unit 1 that was available for Unit 2. Unit 2 equipment was declared inoperable and a timely report to the NRC was made, however, the licensee failed to make a timely report for equipment identified after the inspection in Unit 1. The required report to

the NRC for Unit 1 was made at 1205 on March 27, 1997, following the inspectors notification to the licensee that the failure to report was a violation (50-315/97004-03(DRP)).

Environmental qualification of equipment is necessary to ensure equipment will perform its intended function when exposed to the environment resulting from postulated accidents. Flood-up tubes perform an environmental qualification function for electrical conductors not qualified for submergence in water after a LOCA. The licensee was still evaluating what flood-up tubes were affected and what effects tube cracking had on equipment operability. The environmental qualification of equipment associated with cracked flood-up tubes is an unresolved issue (50-315/316-97004-07(DRP)).

c. Conclusions

The licensee conservatively expanded the scope of their inspection to Unit 2 after identifying cracks in Unit 1 flood-up tubes. Following the identification of flaws in two Unit 2 flood-up tubes, the licensee declared the affected equipment inoperable and made a required report to the NRC.

The environmental qualification of equipment associated with cracked flood-up tubes was an unresolved issue. A violation was identified when the licensee failed to make a timely report to the NRC concerning equipment that had been identified as inoperable due to the cracked flood-up tubes in Unit 1.

E3 Engineering Procedures and Documentation

E3.1 Configuration Control for Testing of the Control Room Ventilation System (Both Units)

a. Inspection Scope (37551)

During the follow-up to a regional request for information the inspectors questioned the control of the test boundary for the CREVS. The inspectors interviewed licensee personnel and reviewed the licensee's testing procedure, **12-EHP 4030.STP.229, Revision 2, Control Room Emergency Ventilation System.

b. Observations and Findings

During routine follow-up to a regional request for information the inspectors began questioning the control of the test boundary for the CREVS. The inspectors observed that the status of the auxiliary building emergency exhaust system (referred to as the AES fans) was not controlled during testing of the CREVS.

The control room pressure envelope included an opening to the control room cable vault. The cable vault directly communicates with the auxiliary building ventilation

system. Even though the cable vault door was closed with a hatch, the inspectors were concerned that enough air could flow between the rooms that the cable vault could reduce the positive pressure in the control room.

During routine plant operations only one AES fan is operating, however, following a safety injection signal all AES fans operate. This significantly changes the negative pressure in the auxiliary building which could reduce the positive pressure in the control room. The licensee's CREVS test procedure did not address the status of the AES fans. Thus during most testing, only one AES fan was operating.

Following the inspectors concerns with the testing configuration, the licensee performed a test of the CREVS with all AES fans operating. No difference could be observed in the CREVS positive pressure between one AES fan and all AES fans operating. Subsequently, the licensee initiated a procedure change to add the AES fan configuration to the testing procedure.

c. <u>Conclusions</u>

The inspectors identified questions concerning the licensee's testing procedure for the control room emergency ventilation system. After promptly performing a test to verify there were no operability concerns the licensee initiated a procedure change request in order to better control the test configuration.

IV. <u>Plant Support</u>

R1 Radiological Protection and Chemistry Controls (71750)

During the resident inspection activities, routine observations were conducted in the areas of radiological protection and chemistry controls using Inspection Procedure 71750. No discrepancies were noted.

S1 Conduct of Security and Safeguards Activities (71750)

During normal resident inspection activities, routine observations were conducted in the areas of security and safeguards activities using Inspection Procedure 71750. No discrepancies were noted.

F1 Control of Fire Protection Activities (71750)

During normal resident inspection activities, routine observations were conducted in the area of fire protection activities using Inspection Procedure 71750. No discrepancies were noted.

X1 Exit Meeting

The inspectors presented the inspection results to members of the licensee management at the conclusion of the inspection on March 29, 1997. The licensee requested additional information on several of the findings presented.

- There was considerable discussion between the NRC inspectors and the licensee personnel present concerning Section M3.1, "Questions Concerning Surveillance Tests of the Turbine Driven Auxiliary Feedwater Pump." Specifically, licensee personnel disagreed with the NRC position that the previous TS surveillance required that the TDAFWP be able to achieve 700 gpm at full discharge pressure with any secondary side steam pressure of greater than 310 psig (e.g., 311 psig). Licensee personnel stated that the TDAFWPs were not required to provide full flow at SG pressures below 550 psig. The inspectors stated that it was the NRC's position that the previous TS surveillance requirement did require full rated flow at 310 psig SG pressure. Licensee personnel stated that they would agree to disagree.

- During discussions concerning the licensee's failure to report following the identification of flawed Unit 1 flood-up tubes, the inspectors stated that it appeared that the licensee had not recognized the need to make a report. In response, licensee personnel stated that they had been evaluating the need to report but had been slow in reaching a conclusion.

PARTIAL LIST OF PERSONS CONTACTED

<u>Licensee</u>

#M. Ackerman, Manager Nuclear Licensing
#J. Allard, Maintenance Superintendent
#G. Arent, Operations Procedure Supervisor
#K. Baker, Manager Production Engineering
#P. Barrett, Director Performance Assurance
#A. Blind, Site Vice President
#S. Brewer, Manager Regulatory Affairs
#M. Depuydt, Licensing Coordinator
#S. Farlow, Supervisor I&C Engineering
#M. Finissi, Supervisor Electrical Systems
#R. Gillespie, Operations Superintendent
#C. Golden, System Engineer
#D. Hafer, Manager Plant Engineering
#S. Hodge, Manager Work Control
#J. Kobyra, Manager Nuclear Engineering
#D. Londot, Environmental
#D. Loope, Training Manager
#A. Lotfi, Performance Engineer
#D. Morey, Chemistry Superintendent
#D. Noble, Radiation Protection Superintendent
#F. Pisarsky, Supervisor, Component Engineering
#T. Postlewait, Site Engineering Support Manager
#T. Quaka, Project Management & Inst. Services
#P. Russell, Plant Protection Superintendent
#J. Sampson, Plant Manager
#P. Schoepf, Manager Safety-Related Systems

#L. Smart, Licensing Coordinator
#D. Spencer, Performance Engineering
#M. Stark, Supervisor Performance Testing
#A. Verteramo, Supervisor Reactor Engineering
#J. Wiebe, Manager Engineering and Analysis

#Denotes those present at the March 27, 1997 exit meeting.

INSPECTION PROCEDURES USED

IP 37551	On-site Engineering
IP 60710	Refueling Outage
IP 61726	Surveillance Observations
IP 62703	Maintenance Observation
IP 71707	Plant Operations
IP 71750	Plant Support Activities

ITEMS OPENED and CLOSED

Opened

50-316/97004-01a(DRP)	VIO	Inadequate Procedure resulted in Inadvertent ESF Actuation
50-315/97004-01b(DRP)	VIO	Failure to Follow Procedures (FME Practices)
50-315/97004-01c,d(DRP)	VIO	Failure to Follow Procedures (Missing Cage Spacers)
50-315/316/97004-02a(DRP)	VIO	Failure to Implement Adequate Corrective Action (Taylor Mod 30 Controller Failure)
50-315/316/97004-02b(DRP)	VIO	Failure to Implement Adequate Corrective Action (Spiral Wound Gasket Material in RCS)
50-315/97004-03(DRP)	VIO	Failure to Make Timely 50.72 Report
50-315/316/97004(DRP)	VIO	Failure to Perform 50.59 Evaluation (Ventilation Catch Basin in CR Panels)
50-315/97004-05(DRP)	DEV	Overpower Chart Recorder Pen Inoperability
50-315/97004-06(DRP)	URI	Failure to Address Check Valve Operability
50-315/316-97004-07(DRP)	URI	Environmental Qualification of Equipment Associated with Cracked Flood-up Tubes

Closed

None

List of Acronyms

AEP	American Electric Power
AR	Action Request
BOP	Balance of Plant
CFR	Code of Federal Regulations
CR	Condition Report
CREVS	Control Room Emergency Ventilation System
DRP	Division of Reactor Projects
ECCS	Emergency Core Cooling System
ESF	Engineered Safety Features
FMEZ	Foreign Material Exclusion Zone
gpm	gallons per minute
JOA	Job Order Activity
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
MDAFWP	Motor Driven Auxiliary Feedwater Pump
MHI	Maintenance Head Instruction
MHP	Maintenance Head Procedure
NRC	Nuclear Regulatory Commission
OHP	Operations Head Procedure
PDR	Public Document Room
PMI	Plant Manager's Instruction
PMP	Plant Manager's Procedure
PMSO	Plant Managers Standing Order
psig	Pounds per Square Inch Gage
RHR	Residual Heat Removal
RG	Regulatory Guide
RO	Reactor Operator
RWST	Refueling Water Storage Tank
SI	Safety Injection
S/G	Steam Generator
SS	Shift Supervisor
TDAFWP	Turbine Driven Auxiliary Feedwater Pump
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
US	Unit Supervisor