Indiana Michigan
Power Company
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Buchanan, MI 49107 1395

AEP

INDIANA
MICHIGAN
POWER

June 5, 1997

AEP:NRC:1260C
10 CFR 2.201

Docket Nos.: 50-315
50-316

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D. C. 20555

Gentlemen:

Donald C. Cook Nuclear Plant Units 1 and 2
NRC INSPECTION REPORTS NO. 50-315/97004 (DRP)
AND 50-316/97004 (DRP) REPLY TO NOTICE OF VIOLATION

This letter is in response to a letter from J. L. Caldwell, dated May 6, 1997, that transmitted a notice of violation and a notice of deviation to Indiana Michigan Power Company. The notice of violation contained a total of eight violations of NRC requirements identified during an NRC inspection conducted from February 16, 1997, through March 29, 1997. The violations pertain to procedures, corrective actions, reportability requirements, and 10 CFR 50.59 issues. Our response to these violations is provided in attachment 1.

The notice of deviation involves inoperability of control room power range pen recorders. Our response to this item is provided in attachment 2.

Sincerely,

E E Fitzpatrick

E. E. Fitzpatrick
Vice President

SWORN TO AND SUBSCRIBED BEFORE ME

THIS 5th DAY OF June, 1997

Linda L. Boelcke
Notary Public

My Commission Expires 01-21-2001

vlb

Attachments

LINDA L. BOELCKE
Notary Public, Berrien County, MI
My Commission Expires January 21, 2001

IE01
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Previously processed w/ incorrect letter date

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PDR ADOCK 05000315
G PDR

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9706090357 970505
PDR ADOCK 05000315
G PDR

090095

c: A. A. Blind
A. B. Beach
MDEQ - DW & RPD
NRC Resident Inspector
J. R. Padgett

ATTACHMENT 1 TO AEP:NRC:1260C

RESPONSE TO NOTICE OF VIOLATIONS

During an NRC inspection conducted from February 17, 1997, to March 29, 1997, four violations of NRC requirements were identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions", NUREG-1600, the violations are listed below.

NRC Violation 1a

"10 CFR 50 Appendix B, Criteria V, Inspections, Procedures, and Drawings, requires in part, that activities affecting quality shall be prescribed by procedures of a type appropriate to the circumstances and shall be accomplished in accordance with these procedures.

Contrary to the above,

> The inspectors identified that Procedure 02-OHP 4023.ES-01 "Reactor Trip Response", revision 11, dated 11/21/96, was not appropriate to the circumstances because it did not contain guidance for adequately controlling steam generator (SG) levels while actions were being taken to minimize the reactor coolant system cooldown rate. As a result, on March 11, 1997, a Unit operator reset a turbine driven auxiliary feed pump (TDAFP) too close to the low-low SG level setpoint which resulted in an inadvertent Engineering Safeguard Feature actuation.

This is a Severity Level IV violation (Supplement I)."

Response to Violation 1a

1. Admission or Denial of the Alleged Violation

   Indiana Michigan Power Company admits to the violation as cited in the NRC notice of violation.

2. Reason for Violation

   This violation resulted from incomplete guidance in procedure 02-OHP 4023.ES-0.1, "Reactor Trip or Safety Injection", that allowed the restoration of the TDAFP prior to the unit being in a stable condition.

   During the performance of 02-OHP 4023.ES-0.1, the control room team is allowed to remove the TDAFP from service if sufficient feedwater is being supplied to the SGs from the two motor driven auxiliary feedpumps. This flexibility to remove the TDAFP from service provides the operators with additional reactor coolant system (RCS) temperature control.

   Technical specifications (T/Ss) 3.7.1.2 and 3.3.2.1 require the TDAFP be operable and capable of automatically starting in mode 3. To comply with these requirements, ES-0.1 directs the TDAFP governor to be reset and the valve alignment to meet the standby readiness requirements. The auto start function is enabled after all standing automatic start signals have cleared. During the post-trip scenario the standing automatic start signals are the low-low SG level on two of four SGs, and the anticipated transient without scram mitigation system actuation circuitry (AMSAC) signal. The

AMSAC signal occurs after all high power trips and is only required above 40% power. The AMSAC signal is then cleared manually during the performance of ES-0.1. The SG low-low level actuation signals are cleared by recovery of SG levels, utilizing the AFW pumps.

During the post trip recovery on March 11, 1997, the AMSAC signal was reset prior to the complete recovery of all SG levels to above the low-low automatic actuation setpoint. The #21 SG level lagged the others, as the loss of main feedwater to that SG was the initiating event which resulted in the reactor trip, and continuous feeding of the SGs was in progress to recover secondary side inventory levels. While filling the SGs, small oscillations normally occur in the sensed level. With the #21 SG level still below the low-low setpoint, a small oscillation occurred in #23 SG that caused the TDAFP auto start signal to clear at its high point, followed by the engineered safety feature (ESF) actuation when it subsequently dropped and went below the ESF setpoint. Because the setpoint has a 1% reset deadband, it is extremely sensitive to minor oscillations.

Due to the incomplete guidance provided in the emergency procedure, emphasis was placed on the restoration of the TDAFP to standby readiness, rather than on stabilizing SG levels above the ESF actuation setpoint prior to securing the TDAFP and placing it in standby readiness.

3. Corrective Action Taken and Results Achieved

The TDAFP started as designed and performed its desired function. Manual control of the SG levels during the post trip recovery continued. No immediate corrective actions were required.

4. Corrective Actions to Avoid Further Violations

The post-trip recovery procedures will be revised regarding placement of the TDAFP in standby readiness. These revisions will allow operators flexibility in equipment management during post trip responses, so that the operator may focus attention on the plant response as post-trip stabilization occurs, while continuing to meet the requirements of the T/Ss for auxiliary feedwater and ESF actuations.

An engineering review of the SG low-low level instrument deadband is being performed. The purpose of the review is to determine the appropriateness of the 1% reset deadband. This review will be completed prior to the next scheduled calibration surveillance of the associated instruments.

5. Date When Full Compliance Will Be Achieved

Full compliance will be achieved by September 1, 1997, with the completion of the engineering review of the reset deadband, and the revision of the appropriate post trip recovery procedures.

NRC Violation 1b

"On March 23, 1997, the inspectors identified that the licensee failed to follow instructions when personnel working adjacent to the refueling cavity in a foreign material exclusion zone, failed to secure light hand tools to themselves by way of a lanyard or tagline, and failed to restrain tools in the FMEZ when they set the tools down. These actions were required by Plant Manager's Instruction (PMI) 2220, "Foreign Material Exclusion", revision 9, dated 3/26/96.

This is a Severity Level IV violation (Supplement I)."

Response to NRC Violation 1b

1. Admission or Denial of the Alleged Violation

   Indiana Michigan Power Company admits to the violation as cited in the NRC notice of violation.

2. Reason for the Violation

   Contract technicians, under I&M supervision, were making repairs to a dual view camera fixture in a foreign material exclusion zone (FMEZ) when they were observed using hand tools with lanyards attached to the tools, but not secured to a person or fixed object. This condition resulted from a misinterpretation of the requirements of plant procedure 12 PMP 2220.001.001, "Foreign Material Exclusion" (FME). Section 5.2.7 of this procedure states, in part, "Light hand tools shall be secured to the person using them by way of a lanyard or tagline." However, further on in the same procedure under a section entitled "Securing Tools" (attachment 2, part 6a) it is stated "Tools or equipment which could fall into openings beyond the reach of personnel MUST be secured with a lanyard or tag line, where practical." The lanyards were felt to be impractical by the workers involved in the job. Because attachment 2 did not require lanyards where impractical, the workers did not use them.

   Additionally, these same contract technicians were observed leaving tools lying loose within an FMEZ. The persons involved had incorrectly assumed that the "intent" of the FME procedure was being followed by the compensatory actions they had taken prior to beginning the equipment repair. These actions included: 1) establishing a laydown area within the FMEZ for the specific purpose of repairing this equipment; and 2) assigning an individual to specifically monitor and control loose parts and tools during the repair evolution. Similar FME practices had been employed at other nuclear sites. However, the Cook Nuclear Plant procedure that governs activities within an FMEZ (12 PMP 2220.001.001) specifically mandates the use of lanyards, and does not recognize other methods of material control.

3. Corrective Actions Taken and Results Achieved

   Upon notification of the NRC inspectors' concerns, the project management & installation services (PM&IS) production supervisor contacted the contractor's site coordinator, who reinstructed the technicians on Cook Nuclear Plant FME

requirements. No additional problems relating to hand tool usage were recorded during the remainder of the project.

4. Corrective Actions To Avoid Further Violations

Procedure 12 PMP 2220.001 will be revised prior to the fall 1997 unit 2 outage. This revision will eliminate the discrepancies noted within the procedure, and provide the flexibility for using other methods of material control.

On May 27, 1997, a plant-wide "time-out" was held to highlight management's expectations in the area of procedure compliance. During this period, plant and contract employees (including supervision) were brought together to focus on the usage of plant procedures. PMI-2011, "Procedure Use and Adherence", was reviewed. Emphasized topics included the various levels of procedure usage (continuous use, information use, reference use) and the company policy of strict procedural compliance.

Additionally, PM&IS will hold another procedural compliance "time-out" prior to the fall 1997 unit 2 outage. Procedural adherence issues will be re-emphasized to both I&M and contract personnel (including supervision), as well as to individuals brought in specifically for outage support.

Within thirty days of the end of the outage, PM&IS will also perform a self-assessment in the area of procedure adherence to determine the effectiveness of our procedural compliance efforts.

5. Date When Full Compliance Will Be Achieved

Full compliance was achieved on March 23, 1997, after all physical work had been stopped and the workers were reschooled on Cook Nuclear Plant FME requirements (PMI-2220) and our policy regarding strict procedural compliance.

NRC Violations 1c and 1d

1c. "On March 11, 1997, the licensee identified that during refurbishment of 1-QRV-114, the reactor coolant excess letdown to excess letdown heat exchanger shutoff valve, in 1994, the valve was reassembled without a cage spacer that was required by maintenance procedure 12 MHP-5021.001.057, "Copes-Vulcan Isolation Valve Maintenance"' revision 1, dated 3/14/97.

This is a Severity Level IV violation (Supplement I).

1d. On March 16, 1997, the licensee identified that during the 1995 refurbishment of 1-NRV-163, the pressurizer spray control valve, the valve was reassembled without a cage spacer that was required by maintenance procedure 12 MHP-5021.001.126, "Copes-Vulcan Bellows Seal Control Valve Maintenance", revision 1, dated 3/13/97.

This is a Severity Level IV violation (Supplement I)."

Response to NRC Violation 1c and 1d

1. Admission or Denial of the Violations

Indiana Michigan Power Company admits to the violation as cited in the NRC notice of violation.

2. Reasons for the Violation

This violation was caused by standards and expectations for contract valve technician performance of work to an in-hand procedure being too low. Proper implementation of the procedures by the technicians was not verified and reinforced by the first line supervisors. An additional factor included the valve technician's lack of familiarity with the specific configuration of this style of valve.

Normal maintenance practice for Copes-Vulcan valve disassembly is to remove the bonnet with the stem intact. This also includes removal of the plug, cage assembly, and cage spacer. During a normal refurbishment the plug and cage assembly are replaced. In these cases, the easiest way to disassemble the internal parts is to cut the stem and let the plug and cage assembly fall into a radwaste container. This usually means that the cage spacer also falls into the waste container. The replacement cage, disc, and stem are normally provided together as a "trim assembly". Because the cage spacer does not see the wear that the plug and cage assembly see, it does not normally need to be replaced during a refurbishment. Therefore, the cage spacer is not included with these parts in a trim assembly. The existing cage spacer must generally be reused when the valve is reassembled.

Copes Vulcan valves have a unique cage spacer configuration, which the technicians did not commonly work with. Nonetheless, the procedure does specifically call for reinstallation of the cage spacer as part of reassembly of the valve internals.

3. Corrective Action Taken and Results Achieved

1-QRV-114 was properly reassembled, with new internals, under JOA R36179-02. This was completed on March 18, 1997.

1-NRV-163 was properly reassembled, with new internals, under JOA C34692-02. This was completed on March 27, 1997.

4. Corrective Actions Taken to Avoid Further Violations

Two Copes-Vulcan valves have been purchased for training purposes. One valve is configured as a "typical" Copes-Vulcan control valve. The other valve is a duplicate configuration of the pressurizer spray valves.

Designation of the cage spacer will be in bold in the reassembly step in Maintenance procedures for Copes-Vulcan valves.

A review of the maintenance procedures for Copes-Vulcan valves will be conducted. Emphasis will be on consolidation

of the procedures and implementation of engineering, planning, or supervisory identification of applicable procedure information based on the internal configuration and application of the valve. This will be completed by September 1, 1997.

Maintenance personnel have been reminded of the need to properly implement in-hand procedures. This means they must read the step, perform the step, document completion of the step, then proceed to the next step.

At the time of the original valve work in 1994, contract supervisors performed hands-on work as well as serving as supervisors. Since 1994, this has been changed and contract supervisors no longer perform hands-on work, but function solely in an oversight role. This is reinforced through regular meetings held during the outage. The contract supervisors are now more involved in preparation and pre-job briefings, and general expectations for contractor performance, especially regarding procedural adherence, is discussed with contract management prior to the start of the outage.

5. Date When Full Compliance will be Achieved

Full compliance was achieved on March 27, 1997. At that time, both valves were properly reassembled.

NRC Violation 2a

"10 CFR 50 Appendix B, Criteria XVI, Corrective Actions, requires in part, that "Measures shall be established to assure that . . . In the case of significant conditions adverse to quality, the (corrective) measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition."

Contrary to the above,

a. On March 11, 1997, in Unit 2, the previous corrective actions to preclude the buildup of electrostatic discharge from affecting Taylor Mod 30 controllers were ineffective in preventing the failure of the controller for feedwater regulating valve 1-FRV-210. This controller failure caused the closure of 1-FRV-210 and a subsequent reactor trip."

This is a Severity Level IV violation (Supplement I)."

Response to NRC Violation 2a

1. Admission or Denial of the Alleged Violation

Indiana Michigan Power Company admits to the violation as cited in the NRC notice of violation.

2. Reason for the Violation

The cause of this violation is an inadequate root cause determination for the previous controller failures. The root cause determination had identified the static electricity but

failed to identify the severity of the problem. Steps had been implemented to reduce the occurrence of static electricity. However, not all processes that could cause static were identified.

Although measures had been taken to reduce static buildup and to provide a means to safely discharge the static, some day-to-day practices that could generate static were not identified, nor was it identified that the methods provided to discharge the static were not always effective. It had been verified that the carpet installed in the control rooms was a static dissipative carpet, humidity levels in the control rooms were being maintained above 40%, and electrostatic discharge (ESD) mats had been placed in front of the control panels. However, after the unit trip, it was discovered the controls of the steam generator level controllers were located at a convenient height to make it common practice for operators to roll over to the controllers in a wheeled office chair and adjust the controls. This rendered the static dissipative carpet and ESD mats installed in front of the control panel ineffective at dissipating static electricity. Engineering had also instructed the operators to discharge their static charge on the control panel prior to contacting controllers but failed to note the painted surfaces on the control panel did not provide for proper grounding.

Additional grounding methods for the controllers had been developed to reduce the vulnerability of the controllers to failure during ESD. An implementation schedule was developed, based on the need to remove a controller from service to perform grounding. Because of this, a number of controllers could not be done with the unit operating. This was judged to be acceptable in view of the actions taken to reduce static buildup and providing a means to discharge the static prior to an operator interfacing with the controller. The controller that failed and caused the March 11, 1997, unit trip was scheduled for the grounding enhancement during the next refueling outage.

3. Corrective Steps Taken and Results Achieved

The enhanced grounding methods were installed in unit 2 during the forced outage from the controller failure and on unit 1 during the refueling outage.

Additional in-house testing of the controller confirmed the manufacturer's identification of ESD sensitivity at the right edge of the faceplate. Testing also showed that sealing the edge of the faceplate prevented static intrusion and doubled the immunity to static discharge. All panel mounted controller faceplates for both units were sealed to prevent static intrusion.

Additional ESD readings were taken in the control rooms while operators were performing routine activities, to more thoroughly quantify the static problem. Testing showed an operator could generate 3KV with a simple act of standing up from a chair. Static electricity also failed to immediately drain while standing on the anti-static carpet and took several seconds to drain while standing on the ESD grounding

mats due to the insulated shoes worn by most operators. Following testing, ESD-proof chairs were installed in the control room and operators were required to wear commercial shoe grounding straps. Follow-up checks indicated that while operators are wearing the grounding strap, static charge buildup would dissipate immediately on contact with the ESD mats and there was no charge buildup while using the ESD chair.

As a point of information, a design change is being finalized to incorporate a failover control system design to prevent single point controller failure in critical instrument loops from shutting down the control loop. Failed controllers will be bypassed with operator notification and, depending on which controller failed, continue in auto or revert to manual for operator control.

4. Corrective Actions To Avoid Further Violations

The cause of this violation was failure to properly identify and fully characterize root causes of the failure. A review and revision of Cook Nuclear Plant PMI-7030, "Corrective Action Program," was recently completed and additional training of personnel in proper root cause analysis is being performed.

5. Date When Full Compliance Will Be Achieved

Full compliance was achieved on May 9, 1997, with the completion of the grounding modifications during the unit 2 forced outage, and on unit 1 during the refueling outage. PMI-7030, revision 23, "Corrective Action Program", was effective May 19, 1997, and personnel training is ongoing.

NRC Violation 2b

"10 CFR 50 Appendix B, Criteria XVI, Corrective Actions, requires in part, that "Measures shall be established to assure that . . . In the case of significant conditions adverse to quality, the (corrective) measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition."

Contrary to the above,

On March 12, 1997, the inspectors identified that the corrective actions following a repeat gasket failure on 1-IRV-311, identified on January 31, 1996, were inadequate to preclude repetition of spiral wound gasket material entering the reactor coolant system, a significant condition adverse to quality. Specifically, the licensee performed an evaluation to determine the effect of spiral wound gasket material in the residual heat removal system; however, no action was taken to remove this material which resulted in the re-introduction of spiral wound gasket material in the reactor coolant system on March 12, 1997."

This is a Severity Level IV violation (Supplement I)."

Response to Violation 2b

1. Admission or Denial of the Alleged Violation

Indiana Michigan Power Company admits to the violation as cited in the NRC notice of violation.

2. Reason for Violation

This violation is the result of an inaccurate root cause determination for the initial failure of the gasket, which occurred in August 1995. The root cause determination was not accurate because information necessary to make an accurate determination was not available at the time of the initial investigation.

A design change previously installed to improve residual heat removal (RHR) flow control replaced the original butterfly valves with a V-notched ball valve, model V100-8in-300lb, manufactured by Fisher Controls. When this design change was engineered, it was not known that excessive turbulence would develop at the valve's downstream flange when the valve was throttled to an intermediate position. This turbulence can result in hydraulic forces capable of damaging the metallic winding of the spiral wound gasket used to seal this bolted connection. Subsequent failures of the gasket provided information not available at the time of the initial investigation. This information led us to the conclusion that the valve and flange gasket are incompatible, and the incompatible design resulted in the gasket failures.

On August 11, 1995, the unit 1 RHR heat exchanger (Hx) bypass flow control valve, 1-IRV-311, downstream flange gasket failed with RHR in service during normal cooldown at the end of cycle 14. When 1-IRV-311 was disassembled for repair, it was discovered that the inside diameter of its gasket was smaller than the inside diameter of the corresponding slip-on flange. This resulted in approximately 0.155 inches of the gasket's metallic spiral windings being exposed to the flow stream, and resulted in gasket failure. The root cause of the initial failure was therefore determined to be an incorrectly sized gasket.

Neither of the other two RHR Hx outlet flow control valves, 1-IRV-310 and 1-IRV-320, have this type of slip-on bolted flange connection or evidenced a flange leak. Therefore, they were not inspected at this time. 1-IRV-311 was returned to service with new spiral wound gaskets of the correct size. The emergency core cooling system (ECCS) and RHR were flushed of debris, and unit 1 began operation for fuel cycle 15.

Shortly after the completion of the unit 1 1995 refueling outage, with the ECCS and RHR in standby readiness, leakage from the downstream joint of 1-IRV-311 again occurred. When the valve was removed for repair on January 31, 1996, its downstream flange gasket was found to have experienced damage similar to the previous failure, with a portion of the spiral windings missing. The root cause of this failure was determined to be incompatibility of the spiral wound gasket with the V-ball type of control valve. A non-metallic fibrous gasket was installed in place of the spiral wound

gasket. Once again, 1-IRV-310 and 1-IRV-320 were not opened because they were not exhibiting any evidence of leakage, nor were they suspected of susceptibility to this type of failure as their throttling characteristics differ from 1-IRV-311.

As a precautionary measure in March of 1996, 2-IRV-311, the unit 2 RHR Hx bypass flow control valve, was opened for inspection prior to the unit 2 refueling outage. This valve had not evidenced leakage at the downstream joint; however, its spiral wound gasket was found to be damaged upon valve disassembly. This provided the first evidence that the flange gasket could become damaged without manifesting external leakage. A fibrous gasket was installed in place of the spiral wound gasket. During the refueling outage, the spiral wound gaskets were removed from 2-IRV-310 and 2-IRV-320 and replaced with fibrous gaskets. The spiral wound gaskets removed from 2-IRV-310 and 2-IRV-320 were intact, reinforcing the conclusion that the 1-IRV-310 and 1-IRV-320 were not at risk for this type of failure.

During the recent unit 1 refueling outage, a visual inspection of the reactor's lower core plate revealed more spiral wound gasket debris than would have been expected from the failure of 1-IRV-311 discovered in January of 1996. Up to this point, all failures of the spiral wound gasket were believed to be isolated to the RHR Hx bypass flow control valve used in the normal cooldown circuit. Although 1-IRV-310 and 1-IRV-320 had no evidence of leakage, they became suspect as another potential source of debris. When each valve was disassembled for an internal inspection, their downstream spiral wound gaskets were found partially unwound.

On March 3, 1997, during the unit 1 RCS/ECCS as found pressure isolation valve (PIV) leak test, it was determined that two PIV check valves had failed their leak test due to the presence of gasket fragments. This debris was subsequently removed and an as-left leak test for all PIVs was performed in April 1997 to demonstrate the class I pressure boundary was intact prior to the beginning of cycle 16.

3. <u>Corrective Action Taken and Results Achieved</u>

The spiral wound gaskets were removed from all RHR flow control valves in both units. Corresponding bolted connections are now sealed with fibrous gaskets which are not susceptible to this form of erosion induced by localized turbulent flow. The RHR piping network branches and ECCS branches in both units 1 and 2 have been flushed to remove foreign material debris, including gasket fragments.

4. <u>Corrective Actions To Avoid Further Violations</u>

It was confirmed that no other incompatible gasket design of this nature was installed in a system relied upon to achieve safe shutdown or mitigate the consequences of an accident.

5. Date When Full Compliance Will Be Achieved

Full compliance was achieved on March 21, 1997, when the last spiral wound gaskets were replaced for 1-IRV-310 and 1-IRV-320.

NRC Violation 3

"10 CFR Part 50.72, paragraph (b)(2)(i), requires that any event, found while the reactor is shut down, that, had it been found while the reactor was in operation, would have resulted in the nuclear power plant, including its principal safety barriers being in an unanalyzed condition that significantly compromises plant safety, be reported to the NRC within four hours of occurrence.

Contrary to the above, the licensee failed to make a timely report in accordance with 10 CFR 50.72(b)(2)(i) when on March 21, 1997, inspection of flood-up tubes in Unit 1 identified cracks in nine tubes and the equipment associated with these flood-up tubes was declared inoperable.

This is a Severity Level IV violation (Supplement I)."

Response to NRC Violation 3

1. Admission or Denial of the Violation

Indiana Michigan Power Company admits to the violation as cited in the NRC notice of violation.

2. Reasons for the Violation

The primary reason for the violation was the low emphasis placed on resolution of an indeterminate reportability condition. Environmental qualification (EQ) issues are complex. The personnel who made the initial reportability decision when the degraded condition was identified on unit 1 were unfamiliar with EQ issues as they relate to system and component operability. It was decided to submit the condition for further reportability evaluation via the process embedded in our corrective action program.

The resulting timetable did not appropriately reflect NRC expectations for promptly evaluating and reporting degraded conditions. The parallel work to inspect, evaluate, and repair tubes in the operating unit 2, took priority over further evaluation of the unit 1 conditions. This prioritization of resources was appropriate based on the safety significance of the condition in the operating unit versus the shutdown unit; however, it extended an already unacceptable delay in the reporting of the unit 1 condition.

A contributor to the length of the delay in reporting was the completion of the evaluation to confirm all inoperable equipment. This provided for determination of the complete safety significance prior to making a final reportability determination. Of the original nine cracked tubes, only seven resulted in declaring equipment inoperable. Twenty-three devices were serviced by the conduit in the seven floodup tubes, and of these, only thirteen devices were confirmed to be inoperable.

3. Corrective Action Taken and Results Achieved

The unit 1 condition was reported to the NRC Operations Center on March 27, 1997 under 10 CFR 50.72(b)(2)(i), degraded condition found while the reactor is shut down.

4. Corrective Action Taken to Avoid Further Violations

10 CFR 50.72 itself does not give guidance on timeliness of reporting when the issue requires evaluation. When cause exists to question the reportability of an issue, our philosophy is that the reportability evaluation will be prompt.

To better define this, we are officially adopting a philosophy similar to what we use to establish the threshold for making operability determinations, as promulgated in generic letter 91-18.

The reportability evaluation period will be predicated on the reasonable expectation that the issue is not reportable, and that further processing will support that expectation. In the absence of reasonable expectation, or mounting evidence suggesting that the outcome will be "reportable", the issue will be reported. Subsequent evaluation may conclude that the issue is, in fact, "not reportable". In such a case, the report will be retracted. This philosophy has been communicated to personnel with responsibility for making reportability determinations. PMP 7030.001.001, "Prompt NRC Notifications", will be revised to incorporate this philosophy. This will be completed by July 25, 1997.

This philosophy has recently been demonstrated by our organization. One reference is a report made under 10 CFR 50.72(b)(1)(i)(B) and 50.72(b)(1)(ii)(B) when an improperly installed plexiglas basin was found to possibly be interfering with control room emergency ventilation operation. This report was retracted when the evaluation determined the condition had only a small impact on system performance. Additionally, an ESF actuation report was made under 10 CFR 50.72(b)(2)(ii) when control power fuses blew on the intermediate range nuclear instrumentation. This report has also been retracted based on further evaluation.

Shift technical advisors and members of the licensing group have been provided with general information relating to the environmental qualification of safety related equipment, and the conditions that contribute to equipment operability.

5. Date When Full Compliance Was Achieved

Full compliance was achieved when the cracked floodup tubes in unit 1 were reported to the NRC Operations Center on March 27, 1997.

NRC Violation 4

"10CFR 50.59 Changes, Tests and Experiments, section (b)(1), requires in part that the licensee shall maintain records of changes in the facility and that these records must include a written safety evaluation which provides the bases for the

determination that the change does not involve an unreviewed safety question.

Contrary to the above, on March 6, 1997, the licensee identified that a plexiglass cover was installed below the return air duct to the unit 2 control room without a proper 50.59 safety evaluation. This plexiglass cover had the potential of affecting the operability of the unit 2 control room emergency ventilation system (CREVS).

This is a Severity Level IV violation (Supplement I)."

Response to NRC Violation 4

1. Admission or Denial of the Alleged Violation

Indiana Michigan Power Company admits to the violation as cited in the NRC notice of violation.

2. Reason for the Violation

The cause of this violation is inadequate procedural guidance. Specifically, the procedure regarding the administration of "Temporary Modifications", 12 PMP 5040.MOD.001, revision 5, defined a temporary modification (TM) as follows:

> Any configuration change that exists on plant systems, components, or structures, (hereafter referred to as equipment) which does not conform to approved plant drawings, approved vendor drawings, or other design documents (i.e., ECPs, EDSs, PDSs) and is being used to maintain operation of the plant. A modification on any equipment being returned to service, though not being used in support of plant operations, where the modification has the potential to adversely affect plant equipment or personnel safety, shall be considered a temporary modification.

At the time of the event, installation of the drip catch basins on the panels near the control room emergency ventilation system (CREVS) intake ducts was not considered a TM per the procedure because it was not to be installed on an operating system, and the basins were not required to maintain operation of the plant.

3. Corrective Actions Taken and Results Achieved

The drip catch basins were removed from both control rooms on March 6, 1997, eliminating potential impact on the CREVS.

Testing of the CREVS was conducted in unit 1 on March 13, 1997, to determine system performance with the drip catch basin installed below the return air intake grille. The pan was placed in a configuration which mimicked the intermittent position of the unit 2 intake pan during operation of the system for blackout testing. The tests performed verified compliance with T/S 4.7.5.1 and habitability dose calculations.

The impact on the unit 1 system was used to analyze the status of the unit 2 system, based on data obtained during the last surveillance test for unit 2. The result fell well within the acceptable range required for operability. Based on the test findings and capability of the unit 2 pressurization system, the unit 2 control room ventilation system remained operable with the catch basin partially obstructing the flow.

4. Corrective Actions to Avoid Further Violations

The TM procedure, 12 PMP 5040.MOD.001, will be revised to stress that any installation, regardless of whether installed on an operating system or not, should be considered a TM if there is reasonable expectation that the potential exists to adversely impact the operation of an adjacent system. The procedure revision will be completed by June 30, 1997.

As an interim measure until the procedure change can be made, management will communicate this event and their expectations regarding the implementation of the TM process to those employees that may be involved in making the decision to invoke the TM process. This will be done by June 10, 1997.

5. Date When Full Compliance Will Be Achieved

Full compliance was achieved on March 6, 1997, when the basins were removed.

ATTACHMENT 2 TO AEP:NRC:1260C

RESPONSE TO NOTICE OF DEVIATION

Notice of Deviation

"During an NRC inspection conducted February 16 through March 29, 1997, a deviation of your actions committed to in the updated Final Safety Analysis Report (UFSAR) was identified. In accordance with the "General Statement of Policy and Procedures for NRC Enforcement Actions, NUREG-1600, the deviation is listed below.

> UFSAR Section 7.4.1 stated, in part, "The power range channels are capable of recording overpower excursions up to 200 percent of full power."
>
> Contrary to the above, on February 25, 1997, the NRC inspectors identified three of four recorder pens inoperable for the power range channels that were capable of recording overpower excursions up to 200 percent of full power. In addition, licensee personnel stated that since June of 1991 the pen's failure rate was such that the percent unavailability average was 14.9 percent. The pens failure rate was such that they were not capable of recording overpower excursions."

Response to NRC Notice of Deviation

1. Reasons for the Deviation

The deviation states that the resident inspector identified that the power range channels capable of recording excursions up to 200 percent of full power, as described in the UFSAR, were found with three of the four channels incapable of performing this function. An historical review identified that this particular recording capability has been challenged in the past including significant periods of recorder unavailability.

The cause for the excessive failures is the relative fragility of the servo-amplifier electronics and overall age. The "fragility" of the electronics is exacerbated by the original time response specification and by the need for specialized analog components (state of the art in the late 1960s) to perform this function. The original design philosophy was to capture the span of the Westinghouse Nuclear Instrumentation Power Range channels, 0-200 percent power. In order to capture this range of power, a very fast recorder was believed to be required. The time response requirements have led to a design that has been difficult and expensive to maintain. Very few replacement parts are available from the vendor and these recorders will not be able to be maintained in the near future.

The inoperability periods are influenced by the fact these recorders are not quickly corrected when identified as requiring service. Long repair-by dates are stipulated by the work control process based on the recorders' regulatory significance and the lack of operational usefulness on a daily basis. No surveillance data is required by operators on these recorders and the normal power level is recorded on different instruments in the control room. This led to the lack of attention to these recorders by control room operations personnel.

2. Corrective Actions Taken and Results Achieved

Corrective action was taken concerning the three failures noted in this deviation. The unit 2 recorder 2-SG-14 was calibrated and the failed pen returned to service on March 13, 1997. Unit 1 was in a refueling outage and the concerns were addressed in section 3 of this response.

3. Corrective Actions to Avoid Further Deviations

The corrective actions to avoid further deviations include improving the control board monitoring to identify substandard equipment, increase importance of all control room instrumentation/recorders in the work control process, and update the specific recorders mentioned in this deviation to allow ease in their maintenance.

These actions were accomplished by the following changes:

The operations department standard OPP-1, "Control Room Control Board Monitoring During Non-emergency Operation Conditions", was revised to stress the importance of control room panel awareness during every day operation. This issue was discussed at the following shift manager's meeting and communicated to the operator crews.

The work control standard that placed time requirements on the repair of critical control room recorders was revised to include all control room recorders. Control room recorders requiring maintenance shall be prioritized to be worked within five to fourteen days as determined by the operations department as per the 1997 AEPNGG site operating and maintenance plan.

The Tracor Westronics recorders were removed from unit 1 and their points placed on an existing Yokogawa recorder in the control room. Similar changes are planned for the unit 2 control room instrumentation. These recorders will allow easier maintenance and thus reduce the unavailability.

4. Date When Corrective Action Will be Completed

The unit 1 corrective actions were completed prior to the restart after the refueling outage. Unit 2 corrective actions will be completed during the next refueling outage scheduled for the fall of 1997.