U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Reports No. 50-315/86004(DRP); 50-316/86004(DRP)

Docket Nos. 50-315; 50-316 Licenses No. DPR-58; DPR-74

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

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

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

Inspection Conducted: January 21, 1986 through February 18, 1986

Inspectors: B. L. Jorgensen

J. K. Heller

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Approved By: for C. W. Hehl, Chief
Projects Section 2A

3-25-86
Date

Inspection Summary

Inspection on January 21, 1986 through February 18, 1986 (Reports No. 50-315/86004(DRP); 50-316/86004(DRP))

Areas Inspected: Routine unannounced inspection by the resident inspectors of licensee actions on previously identified items; operational safety verification; reactor trip/safety system challenge review; surveillance; reportable events; and independent inspection activities. The inspection involved a total of 256 inspector-hours by four NRC inspectors including 20 inspector-hours during offshift.

Results: Of the six areas inspected, no violations or deviations were identified in four areas. The two violations (Level IV - failure to properly review and control procedure changes, Paragraph 2.c; Level V - failure to meet requirements of Technical Specification for compensatory sampling with equipment inoperable, Paragraph 6) were identified with one in each of the remaining areas.

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DETAILS

1. Persons Contacted

   W. G. Smith, Jr., Plant Manager
   *B. Svensson, Assistant Plant Manager
   *A. Blind, Assistant Plant Manager
   *T. Kriesel, Technical Superintendent-Physical Sciences
   *J. Allard, Maintenance Superintendent
   K. Baker, Operations Superintendent
   *J. Stietzel, Quality Control Superintendent
   *L. Mathias, Administrative Superintendent
   *L. Gibson, Technical Superintendent-Engineering
   *C. Murphy, Operations-Production Supervisor
   D. Draper, Operations Procedure Coordinator
   M. Horvath, Quality Assurance Supervisor
   *D. McAlhany, Quality Assurance (AEPSC)
   *R. Sims, Shift Technical Advisor
   T. Postlewait, Performance Supervising Engineer

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

   *Denotes personnel attending exit interview February 19, 1986.

2. Licensee Actions on Previously Identified Items

   a. (Open) Unresolved Item (315/85028-01; 316/85028-01); apparent failure to perform surveillance testing at the required frequency and failure to perform adequate surveillance testing. This item has three attributes, each of which has been determined to represent a Violation. First, as described in Paragraph 3.a. of the referenced Report, various CHANNEL FUNCTIONAL TESTS required to be performed each month were, prior to August 1985, being performed only once each two months. Second, as described in Paragraph 3.c. of the referenced report, a motor-driven auxiliary feedwater pump loss of voltage relay required to be tested each refueling had, prior to August 1985, never been tested. Third, as described in Paragraph 3.d. of the referenced Report, selected CHANNEL CALIBRATIONS (defined as requiring inclusion of the sensor) had, prior to August 1985, been performed excluding the sensor. These matters have been discussed with the licensee during meetings with the NRC Region III staff; specifically during an Enforcement Conference held on November 13, 1985. They remain under evaluation for appropriate enforcement action, including potential escalated enforcement. Though no Notice of Violation concerning these matters is being issued with this report decisions concerning application of proper enforcement sanctions are pending. The licensee is being officially notified in writing via the transmittal letter for this report that the items are considered Violations. In the future this item will be tracked as Violation (315/85028-01; 316/85028-01).

b. (Open) Unresolved Item (315/85028-02; 316/85028-02): failure to conduct a channel functional test following a channel calibration. NRC has not determined if this matter is a Violation. NRC will correspond with the licensee concerning this item at a later date.

c. (Closed) Unresolved Item (315/85028-03; 316/85028-03): apparent failure to provide adequate reviews and controls on temporary procedure changes. This item has also been determined to be a Violation, as discussed previously with the licensee. A Notice of Violation concerning this item is being issued with this report. A brief review of the facts is appropriate. During conduct of the inspection documented under Reports No. 315/85028; 316/85028 the inspectors observed a procedure in use which had apparently been altered by a pen and ink change. Following up this observation, a large number of similar procedures (Control and Instrument group test procedures) were reviewed from the files. Though the sample was large, it constituted only a fraction of the total number of procedures of this type. A total of eleven procedures were found which had been altered; however, required review and approval for such alterations had not been applied. Technical Specifications (both Units) Paragraphs 6.8.2 and 6.8.3 require prior review and approval of all procedure changes; with permanent changes reviewed and approved by the Plant Nuclear Safety Review Committee (PNSRC) and the Plant Manager; and temporary changes (not altering the intent of the procedure) requiring approval of two members of the management staff including one Senior Reactor Operator license holder. Subsequent PNSRC and Plant Manager approval of temporary changes must follow within 14 days. In the examples identified by the inspectors, neither type of review and approval process had been performed. Subsequent to this finding, as stated in the licensee's letter of November 27, 1985 and as described in Inspection Reports No. 315/85041(DRP); 316/85041(DRP), the licensee performed a comprehensive review of all procedures of the subject type, identified and evaluated each instance potentially involving a previously unreviewed and unapproved revision to such procedures, and documented the requisite review and approval as needed. No examples were identified which appeared likely to have caused incorrect procedure performance or invalid data. Preventive actions have included conversations with the personnel apparently involved in the procedure alterations. The discussions focused on a Plant Manager letter dated September 16, 1985 to all supervisors, addressing the use of required controls when making changes to procedures. Since actions to correct and to prevent recurrence of this Violation have already been completed, the licensee will not be required to respond to the Notice of Violation issued herewith. The inspector has no further questions concerning this matter at this time (Violation 315/86004-01; 316/86004-01).

Four violations and no deviations were identified.

3. Operational Safety Verification

The inspector observed control room operation including manning, shift turnover, approved procedures and Limiting Condition for Operation (LCO) adherence, and reviewed applicable logs and conducted discussions with control room operators during the inspection period. Observations of the control room monitors, indicators, and recorders were made to verify the operability of emergency systems, radiation monitoring systems, and nuclear and reactor protection systems, as applicable. Reviews of surveillance, equipment condition, and tagout logs were conducted. Proper return to service of selected components was verified. Tours of the auxiliary building, turbine building, and screenhouse were made to observe accessible equipment conditions, including fluid leaks, potential fire hazards, and control of activities in progress.

Unit 1 operated routinely at approximately 90 percent power throughout the inspection period. The inspector performed a walkdown and review of accessible portions of the Unit 1 "E" (East) Containment Spray System (CTS) using licensee drawing OP-1-5144-6 and procedure 1-OHP 4021.009.001 "Placing Containment Spray in Standby Readiness". Correct flowpath valve positions were verified, and no condition was noted which degraded the system or its major components. It was not possible to verify the correct (closed) position of valve 1-IMO-210 (an automatic opening pump discharge valve) using the local dial indicator at the valve. Control room indication established the valve was correctly positioned. Discussion with the licensee suggested the local indicator is not heavily relied upon to ascertain valve position. Nevertheless, a Job Order was initiated to adjust the dial to the correct onscale reading. Based on a Unit 2 event (discussed below) involving valve identification tag interference with proper valve operation for a small manual valve, the walkdown specifically focused on potential additional examples where an identification tag was positioned so as to create possible indication. No examples were noted in this small sampling.

Unit 2 operated at approximately 80 percent power throughout the inspection period with three exceptions. A Unit trip on February 1, 1986 is discussed in Paragraph 4 below. The two other events both involved licensee initiation of plant shutdown pursuant to Technical Specifications because the Boron Injection Tank (BIT) boron concentration became diluted below the required 20,000 parts per million (ppm). The first event occurred February 7, 1986. Operators acquiring routine shift readings noted a level increase in the "S" (South) Boric Acid Storage Tank (BAST), which was in service recirculating the BIT. A special boron sampling was requested which showed at 12:05 p.m. that the BIT had been diluted to 17,331 ppm. Recirculation was switched to the "M" (Middle) BAST, a resample called for, and a Unit shutdown commenced. By 1:40 p.m. resampling results demonstrated the BIT concentration was back in specification and the shutdown was terminated. Subsequent investigation of a suspect pair of cross-tie valves from the primary water system disclosed one of the valves had a damaged internal diaphragm which apparently permitted the leakage and resultant dilution. The primary water system had been in service to dilute the primary coolant system in support of the ongoing power increase after recovery from the reactor trip a week earlier.

Five days later, on February 12, 1986 a second dilution of the Unit 2 BIT occurred. In this event, the BIT had been taken off "M" BAST recirculation to permit alignment of the still-diluted "S" BAST through part of the shared piping. The "S" BAST was intended to be pumped down to a holding tank to make room for the addition of sufficient highly concentrated boric acid to return that tank to specification. When the "M" BAST level increased (as observed in the Unit 1 control room, which has the only level indication on this "shared" tank) a special boron sample was again requested which, at 4:48 p.m., showed boron concentration to be 19,047 ppm. Since it was believed the dilution path must be directly through the BIT (which later proved the case) the BIT was immediately restored to recirculation via the "M" BAST (which had not diluted significantly) and resampling called for while a shutdown was begun. By 5:55 p.m. the resample analysis showed the BIT back in specification. The shutdown was terminated. Investigation of this problem found a small (one inch) manual isolation valve separating the "S" BAST from the BIT had not been fully closed because the handwheel had tightened down on a small ball-chain attaching the valve identification tag to the valve, instead of tightening into the valve seat. Some discussions among the inspector and licensee personnel concerning this event suggest the following: first, the valve in question was not the sole isolation valve available and dual isolation could have been established; second, changing "M" BAST level could have been noted sooner had Unit 2 communicated more clearly or forcefully than it did to Unit 1 that changing tank level could indicate a problem and; third, the tag interference is not necessarily indicative of a generic problem because it involved a small manually operated valve on an insulated and heat-traced pipe run (the insulation obscuring the valve stem) and the "old style" plastic identification tag attached with a ball-chain. The licensee is engaged in placing new, color coded metallic permanent identification tags on plant components. Guidance already in existence for such permanent tag placement should, for a valve of this type, result in attachment to the pipe rather than around the valve stem. In fact, prior to the conclusion of this inspection a permanent tag had been made and placed at the valve in question and the old tag and chain removed.

In each of the above instances, the licensee's actions were in compliance with requirements.

The previous Inspection Report (No. 315/85041(DRP); 316/85041(DRP)) discusses some need for improved clarity in the way the licensee controls the turbine driven auxiliary feedwater pump speed controller setting. The instructions given in various procedures were at odds with each other. During this inspection, the licensee completed procedure change sheets to applicable procedures such that these contradictions are removed. He has chosen to control this parameter via an information tag placed at the controller indicating the correct setting as established by monthly testing. Proper controller position will be verified each shift. The inspector has no further questions or concerns in this area.

Finally, the inspector discussed shift staffing, and the licensee's capabilities for maintaining and/or augmenting shift crews as necessary when considering severe inclement weather, with licensee operations management staff. They appeared both sensitive to and prepared for weather emergencies insofar as maintaining adequate shift crews was concerned.

No violations or deviations were identified.

4. Reactor Trips - Safety System Challenge Review

The following event was reviewed by the resident inspectors to determine: the significance of the event; the performance of safety systems; immediate actions taken by the licensee; radiological consequences; and corrective actions taken.

Unit 2 tripped from about 80 percent power at 8:11 a.m. on February 1, 1986 as a consequence of a main generator "unit differential" trip. The generator differential trip was apparently caused in turn by protective relay response to a faulting condition on the 2CD auxiliary transformer, which was providing station power back off the main generator. Plant response to the trip, including fast-transfer of station loads to startup power, was normal.

A fire ensued on the 2CD transformer at a failed bushing atop the unit, and the bus ducting system drew considerable smoke into the adjacent turbine building, making the magnitude and location of the fire uncertain at first. An "Unusual Event" was declared at 8:15 a.m. due to the fire, which was subsequently extinguished by 8:27 a.m. The "Unusual Event" was secured at 9:03 a.m. Licensee response to and management of the fire situation are subject to further review at a later date by specialists from NRC Region III, and will not be addressed further here. Response of the plant, as noted above, was normal; although operators continued running the turbine driven auxiliary feedwater pump longer than needed (perhaps due to focus on the incoming reports relating to the fire) and cooldown proceeded to 532 degrees versus a normal hot standby of 547 degrees (and pressure was around 2,000 psig) before the pump was secured.

Following applicable post-trip reviews and required authorizations the Unit 2 reactor was again taken critical late on February 3, 1986. In the interim, early on February 3, the initial approach to criticality was not proceeding per expectations established by an estimated critical position (ECP) calculation. Extrapolations during the approach suggested the ECP, plus a 500 pcm target band, was going to be exceeded. The approach was terminated, all control banks re-inserted, and a review initiated to determine what happened. An NRC Region III inspector specializing in reactor physics was onsite performing an inspection in that area, arrangements were made for the specialist to review this matter as well. That review was documented in IE Inspection Reports No. 315/86005(DRS); 316/86005(DRS).

No violations or deviations were identified.

5. Surveillance

The inspector reviewed Technical Specifications required surveillance testing as described below and verified that testing was performed in accordance with adequate procedures, that test instrumentation was calibrated, that limiting conditions for operation were met, that removal

and restoration of the affected components were properly accomplished, that test results conformed with Technical Specifications and procedure requirements and were reviewed by personnel other than the individual directing the test, and that deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel.

Performance of all or parts of the following tests was observed:

**1 THP 4030 STP.013	"Pressurizer Pressure Protection Set III"
**1 THP 4030 STP.014	"Pressurizer Pressure Protection Set IV"
**1 THP 4030 STP.005	"Over Temperature and Over Power Protection Set II Surveillance Test (Monthly)"
**1 THP 6030 IMP.095	"OT/T-avg Protection Set II Calibration"

The test designated IMP.095 was required for recalibration of two R/E converters which were determined to be out of specification during initial performance of STP.005. The test designated STP.005 was then repeated (this retest was specifically observed) and all "as left" values appeared to be in specification.

For the following tests, the inspector reviewed the test procedures and/or completed test data for the more recent test performances:

**1 OHP 4030 STP.007E	"East Containment Spray System Operability Test"
**1 OHP 4030 STP.007W	"West Containment Spray System Operability Test"
**1 THP 4030 STP.205A	"Engineered Safeguards Features Time Response Test - Train A"
**1 THP 4030 STP.205B	"Engineered Safeguards Features Time Response Test - Train B"
**1 THP 4030 STP.217A	"Diesel Generator Load Shedding and Performance Test - Train A"
**1 THP 4030 STP.217B	"Diesel Generator Load Shedding and Performance Test - Train B"

The inspector reviewed the technical content of STP.007E and STP.007W (both were Revision 1 with change sheets 1, 2 and 3 incorporated) and found that the procedures appear to demonstrate the operability of the Containment Spray and Spray Additive Systems in accordance with the appropriate monthly Technical Specification surveillance requirements. However, the inspector questions if the cycling of 1-IMO-212, "1E CTS Pump Eductor Supply Valve" and 1-IMO-222 "1W CTS Pump Eductor Supply Valve" meets the intent of ASME Boiler and Pressure Vessel Code, Section XI. The sequencing of STP.007E

and STP.007W is such that valves 1-IMO-212 and I-IMO-222 are cycled (closed-opened-closed) before the valves are stroke-timed in the open position. The inspector discussed this with the Operations Superintendent and the Operations Procedure Coordinator. The Operations Procedure Coordinator agreed to review this item and make the appropriate revisions to STP.007. This is an Open Item pending the Operations Coordinator review (Open Item 315/86004-02).

Technical Specification 3.3.2.1 at Table 3.3-5 specifies an Engineered Safety Feature (ESF) response time of less than or equal to 45 seconds for the Containment Spray System. STP.205A and STP.205B at Step 6.6.A of attachment 4 implements this requirement. The inspector reviewed these procedures and found that parallel spray pump discharge valves (two per pump) have an allowable ESF response time of less than or equal to 60 seconds. This time is footnoted by reference to Attachment 3 of STP.205A or B, explaining why the response time is increased from 45 seconds to 60 seconds. Basically, attachment 3 explains that if the valves are open at least 20 percent, the system resistance is negligible and the spray system will be capable of performing its safety function. The attachment does not state how many seconds it takes for the valve(s) to reach 20 percent open. The inspector discussed this with the Technical Superintendent - Engineering, who initiated an evaluation to show the valves are at least 20 percent open in less than 45 seconds. An analysis that shows 20 percent open will provide negligible flow resistance will be included. Pending further NRC review of this matter, this is considered an Open Item (315/86004-03).

The inspector reviewed completed Attachment 4 to STP.205B (performed November 1985) and STP.205A (performed October 1983). The following were found.

a. STP.205B listed an ESF response time of 60.2 seconds for IMO-220 and documented "Attachment 3 states that valves must be 20 percent open within 60 seconds" which is an incorrect interpretation of Attachment 3. The acceptance criterion was less than or equal to 60 seconds. The significance of the additional 0.2 seconds is unclear. However, this should be resolved when Open Item 315/86004-03 is resolved.

b. STP.205B includes the diesel generator start time and load sequencing time to determine ESF response time, and states these times can be obtained from STP.217B. The inspector reviewed STP.217B (performed June 16, 1985) and found that the timing graphs, which used a multi-pen recorder, did not have a "key" for deciphering which pen tracks what component. With the assistance of a Performance Engineer the key was found in an uncontrolled location. The Performance Engineer committed to incorporate the key into STP.217B. The inspector reviewed a sample of other procedures that used multi-pen recorders and found that the completed procedures adequately identified components. This was discussed at the exit interview with the inspector stressing, and the licensee agreeing, that completed documentation should stand alone.

c. STP.205A documented "N/A" for the requirement to include the load sequencing time when determining the 1E Containment Spray Pump ESF response time. This appears to be in error. The inspector discussed this with the Performance Supervisor concerning how a demonstration of compliance to an overall time limit requirement can be made without one of the time constituents. He agreed to verify the response time, including sequencer loading time, met the 45 second requirement. This is considered an Open Item (Open Item 315/86004-04).

No violations deviations were identified. Three open items were identified.

6. Reportable Events

Through direct observation, discussions with licensee personnel, and review of records, the following Licensee Event Reports (LERs) were reviewed. The review addressed compliance to reporting requirements and, as applicable, accomplishment of immediate corrective action. If indicated "closed", the review showed appropriate corrective action to prevent recurrence had been accomplished in accordance with applicable requirements.

Unit 1

(Closed) RO 315/85005-00: incorrect iodine sample medium. The plant had been using silver zeolite cartridges for iodine collection/analysis since June 1982, contrary to Technical Specification 3.11.2.1 Table 4.11-2, which specifies a charcoal medium for iodine collection in the auxiliary building vent system, and gland exhaust system. The iodine collection medium was changed back to a charcoal cartridge on February 5, 1985 and will be used until a Technical Specification change can be made to allow for the use of the more accurate silver zeolite cartridge. Application for this change is included in a letter, dated January 21, 1986 (AEP:NRC:0956A) written to the Office of Nuclear Reactor Regulation.

(Closed) RO 315/85019-00 and 315/85019-01: low ice condenser basket weights. An April 1985 surveillance indicated that several ice condenser ice basket weights were low. The ice inventory in the ice condenser was below the Limiting Condition for Operation (LCO) in Technical Specification 3.6.5.1.d, for the minimum average ice weight (1220 lb/basket) of sample baskets from each row/group. An extensive ice replenishment program was completed during the Unit 1 1985 outage; the surveillance, 12 THP 4030 STP.211, "Ice Condenser Basket Weighing," was completed three times satisfactorily in 1985 after the replenishment. In addition, Unit 2 satisfactorily completed an ice basket weighing surveillance in August 1985 and plans a replenishment program for 540 baskets for the 1986 outage which begins in February 1986.

(Closed) RO 315/85026-00: ESF actuation-safety injection. The signal occurred due to one channel of pressurizer pressure in test concurrent with loss of the block signal on another channel when the vital instrument bus Control Room Instrument Distribution (CRID) was momentarily deenergized. To prevent recurrence the licensee has added a precaution to the vital

instrument bus power supply transfer procedure (OHP 4021.082.008) that advises the operator to evaluate the status of protection channels prior to power transfer. The licensee has implemented a design change in Unit 1 to replace the CRID inverters (DC-01-2766) and plans to complete the Unit 2 design change during the 1986 outage. The new design power supply can be transferred without deenergizing CRIDS.

(Closed) RO 315/85031-00 and 315/85031-01 (Applies to both Units): incorrect calibration of residual heat flow instrumentation. The licensee discovered a combination of factors had led to instrumentation for RHR hot leg process flow and RHR cooldown flow being inaccurate. The indicated flow exceeded the actual flow, such that use of the flow indication to show compliance to requirements for minimum flow through the reactor coolant system, is suspect. At an indicated 3,000 gpm (corresponding to the minimum flow requirement) actual flow could have been as low as 2,026 gpm. The licensee's supplemental report dated September 9, 1985 contains analyses demonstrating 2,000 gpm is adequate flow for decay heat removal and to avoid boron stratification. One of the subject instruments (per Unit) feeds a low flow alarm which would warn plant operators of loss of flow, so actions could be taken to protect the associated pump and to establish an alternate flow path. The alarm setpoint (intended for 2,000 gpm) could have been set as low as 675 gpm. Considering independent means to identify loss of flow and the substantial time (at least one hour) permitted to correct such loss, accuracy of the alarm setpoint is not considered critical.

At the time of the discovery of this matter in early July, 1985 the inspector briefly reviewed the circumstances with licensee personnel. Replacement of erroneously drawn meter faces (considered the primary deficiency - see IE Inspection Reports No. 50-315/85020(DRP); 50-316/85020(DRP) Paragraph 3.c.) was specifically verified at that time as immediate corrective action. Subsequent reviews indicate all the instruments affected (three per Unit) were identified in the licensee's search for additional examples, and no other examples were found in independent reviews by the resident inspectors. Prevention should be assured by revision of the associated calibration procedures, which is complete, now that correctly drawn permanent meter faces are installed.

Though uncertain, it is likely the licensee operated both Units at various times with (unknowingly) less than the required flow, in violation of Technical Specifications. In such an event, the violation would be of the kind (identified, reported and corrected by the licensee, small safety significance and unrelated to a previous similar violation) for which NRC, under its enforcement policy as stated in 10 CFR Part 2, Appendix C, does not usually issue a Notice of Violation, and no Notice of Violation is being issued in this case.

(Closed) RO 315/85034-00: breach of containment integrity during refueling. Both airlock doors were momentarily opened simultaneously during refueling, identifying a malfunctioning latching mechanism. The mechanism was repaired within about five hours, during which time no further simultaneous openings occurred.

(Closed) RO 315/85035-00: reactor coolant system boron concentration below 2,000 ppm during refueling (two occasions - about 30 ppm below). The fuel vendor evaluated minimum boron concentration necessary to maintain shutdown margin at 1565 ppm, well below the concentrations observed in this event. No positive identification could be made of the source of dilute water, despite an investigation of various possibilities. The licensee believes, since strict control of boron concentration above 2,000 ppm was not required during the full core offload preceding this event, that stagnant RCS volumes (e.g. in idle legs) mixed back into the system following reload and establishment of varying residual heat removal flow paths. This possibility has been addressed by a Standing Order to maintain 2,000 ppm throughout the systems even during periods when there is no fuel in the reactor vessel.

(Closed) RO 315/85037-00: ESF actuations during cold shutdown. Two events occurred as a consequence of modifications to the plant permitted only during cold shutdown. They are considered minor events with respect both to safety significance and to the question whether they may have merited some effort in an attempt to avoid them. Their reportability is based (correctly) on the understanding <u>any</u> ESF actuation not "preplanned" must be reported. The licensee categorized these items as not "preplanned" due to the absence of a specific prior notification to the operators that an actuation was imminent.

(Closed) RO 315/85039-00 (applies to both Units): surveillance performed on wrong fire water ring header valve. This item is similar to RO 315/84025-00 discussed in IE Inspection Reports No. 50-315/84023(DRP); 50-316/84025(DRP) in that it involves discovery, due to flow print verification activities mandated by the licensee's Regulatory Performance Improvement Program, that a valve other than that intended had been subjected to testing due to flow print error. The error was corrected.

(Closed) RO 315/85040-00 (applies to both Units): potential for RHR flow below limits. In review of RO 315/85031-00 discussed above involving RHR flow instrument calibration, the licensee recognized RHR flow paths are available and used which are not equipped with a low flow alarm. Though the license condition which prompted installation of the existing alarms no longer exists, the need to promptly identify loss of RHR flow remains whatever the system alignment, and written instructions to the operators establishing frequency for and documentation on flow verification have been issued.

(Closed) RO 315/85044-00: ESF actuation during cold shutdown. As with RO 315/85037-00 discussed above, these were trivial (but reportable) events related to installation of a design change permissible only with the plant in cold shutdown.

(Closed) RO 315/85052-00: an ESF actuation in the form of a containment purge isolation <u>signal</u> (no purge was in progress so no actual isolation occurred) was caused by component failure in the Critical Control Room Power (CCRP) inverter. Damaged and questionable components within the inverter were replaced and normal electrical lineups restored.

(Closed) RO 315/85054-00: an ESF actuation in the form of a turbine trip signal (the plant was in MODE 3 with the turbine not in service) was caused by steam generator hi-hi level. Level was being maintained above the high deviation alarm point of 50 percent level (at about 60 percent) to perform a calibration procedure. Temperature changes and feedwater leakby increased level to the 68 percent "trip" setpoint undetected by the operator, who was involved in shift turnover. Though this specific event lacked safety significance, operator attentiveness is highly important and was specifically addressed with the operator involved. Job Orders to investigate apparent feedwater isolation valve leakage were written.

(Closed) RO 315/85057-00 and 315/85057-01: an ESF actuation in the form of a reactor trip signal (the plant was in MODE 3 with the control rods inserted and the reactor trip breakers open) was caused by simultaneous de-energization of two power range nuclear instruments to install a design change. Though this specific example lacked safety significance, it occurred because the Unit Supervisor and the instrument technicians involved did not recognize the activity could best be accomplished one channel at a time.

(Closed) RO 315/85059-00: an ESF actuation in the form of a reactor trip signal (plant in MODE 3, trip breakers open) was caused by a technician lifting the wrong leads while performing instrument checks.

(Closed) RO 315/85060-00: an ESF actuation in the form of an actual safety injection and main steam isolation (plant in MODE 3, trip breakers open) was caused by simultaneous conduct of unrelated activities; one of which created indicated high steam line flow while the other created low-low average temperature.

The following Unit 2 item is discussed here for continuity:

(Closed) RO 316/85037-00: an ESF actuation in the form of a reactor trip from about 81 percent power resulted from isolation for maintenance of a safety instrument channel also being used for control circuit input without transferring control to the alternate channel.

Each of the three items immediately above have in common that they were avoidable had plant personnel exercised greater foresight in conduct of activities. The licensee has been requested to specifically address NRC concern in this area, in writing, in response to IE Inspection Reports No. 50-315/85036(DRP); 50-316/85036(DRP).

(Closed) RO 315/85063-00: inoperable main steam flow transmitters. Two transmitters failed independently but simultaneously, indicating no steam flow during a power increase. License action requirements were met, the instruments were repaired and recalibrated, respectively, and returned to service.

(Closed) RO 315/85068-00: an ESF actuation in the form of a main steam line isolation (plant in MODE 3) was caused by performance of a surveillance with temperature below 541 degrees. Reportability was based solely on the lack of prior notification to control room operators that the actuation would occur, such that so far as they were concerned, it was unanticipated. It was considered minor similar to RO 315/85037-00 discussed above.

Unit 2

(Open) RO 316/83014-00: Steam Generator No. 23 Main Steam Isolation Valves Dump Valve, MRV-232, removed for repair. The repair of MRV-232 placed No. 3 Steam Generator Stop Valve in a a less conservative configuration than required by Technical Specification 3.7.2.5, however the redundant dump valve, MRV-231 remained operable, action requirements were met, and the valve was returned to service within four hours. The inspector reviewed several Job Order packages regarding similar repairs to both Units and found that three valves out of sixteen needed repetitive repairs. The preventive maintenance program was discussed with plant personnel. The Preventive Maintenance (PM) procedure for the maintenance department (MHI 5030) included extensive information on items scheduled and frequency of preventive maintenance, and has recently been updated to reference the documentation which resulted in an item being included in the Preventive Maintenance schedule. However, the inspector is leaving this item open until further details on the preventive maintenance program can be reviewed.

(Closed) RO 316/85014-00: an ESF actuation in the form of a safety injection signal (plant in MODE 5) was caused by a momentary voltage drop to two Control Room Instrument Distribution (CRID) buses when a reactor coolant pump was started from the same power source. The CRID electrical alignment was unique to an ongoing design change and would not have been permitted in other MODES.

(Closed) RO 316/85016-00: missing seismic restraints. In review of I.E. Information Notice 85-45 and preparations to address questions/concerns relating to seismic design of selected Westinghouse Incore Flux Mapping Systems (FMS), the licensee discovered restraint devices specified in the original design were never installed on the FMS frame. This circumstance was unique to Unit 2, and was expeditiously corrected, prior to startup from the then existing shutdown.

(Closed) RO 316/85018-00: an ESF actuation in the form of a reactor trip signal (plant in MODE 3, but reactor trip breakers closed) was caused by conduct of routine instrument checks not normally performed with the trip breakers closed. This event has no safety significance but is another example of an "avoidable" actuation.

> Note: the following four items are grouped together due to the interrelationship among them; although all apply to both Units, two were identified first and assigned by the licensee to the Docket for each Unit.

(Open) RO 316/85021-00 (applies to both Units): failure to perform certain instrument channel functional tests at the required frequency. This matter was originally identified in part by the NRC and was described in the associated IE Inspection Report as an Unresolved Item (No. 315/85028-01; 316/85028-01). NRC has subsequently determined this matter to be a Violation, has met with the licensee to discuss it, and is continuing an evaluation relating to the choice of appropriate potential enforcement action. Pending such determination, no Notice of Violation is being issued.

(Open) RO 315/85043-00 and 315/85043-01 (applies to both Units): failure to include primary sensors in channel calibrations. As with the above item, NRC originally identified this item in part, has documented it within the same Unresolved Item (No 315/85028-01; 316/85028-01) and has since determined it to represent a Violation for which appropriate enforcement action is yet to be determined.

(Closed) RO 315/85047-00 and 315/85049-00 (applies to both Units): failure to perform instrument surveillance at the required frequency. These matters were identified by the licensee in performance of reviews stipulated in a Confirmation of Action Letter (CAL) dated August 30, 1985 which was based on the NRC findings discussed above. In that appropriate enforcement action is being developed concerning the similar NRC-identified matters, no Notice of Violation is deemed necessary concerning these items identified, reported and corrected by the licensee pursuant to the CAL based on the NRC items.

(Closed) RO 316/85025-00 (applies to both Units): inadequate control to assure required surveillance completed. This matter was also identified, reported and corrected by the licensee pursuant to the evaluations performed to implement the CAL discussed immediately above.

(Closed) RO 316/85012-00 and 316/85043-00: failure to complete compensatory sampling within required time interval. Each of these events involved late collection of "grab" samples of the Unit 2 auxiliary building ventilation gaseous effluent with the automatic sampling equipment inoperable. Unit 2 Technical Specification 3.3.3.10 requires the effluent monitoring instrumentation be OPERABLE as shown in Table 3.3-13, which lists the Unit vent noble gas activity monitor as Item 3.a, specifying the minimum operable channels permissible as one channel. Pursuant to Specification 3.3.3.10, with less than the minimum number of channels OPERABLE, the licensee must take the ACTION shown in Table 3.3-13, which is ACTION 28 in the case of the vent gaseous monitor. ACTION 28 permits continued operation for up to 30 days provided grab samples are taken at least once per 8 hours. The first event occurred June 3, 1985 when a sample required by 5:00 a.m. was not collected until 5:30 a.m.. The second event occurred December 27, 1985 when a sample required by 4:55 a.m. was not collected until 7:18 a.m.. In accordance with NRC enforcement policy concerning licensee-identified violation which should have been prevented by corrective action for previous similar problems, a Notice of Violation is being issued for the second (December 27) occurrence (Violation 316/85004-02).

Five violations and no deviations were identified. Each of the violations were initially identified by the licensee. One Notice of Violation is being issued.

7. Independent Inspection Activities

a. On February 4, 1986 the licensee discovered the Technical Specification surveillance "grace period" for performing CHANNEL CALIBRATIONS on the post-accident monitoring instrumentation of Table 4.3-10 (Unit 2) was about to expire. The instruments in this Table were overlooked in the licensee's request for a one-time extension of the surveillance interval (for instrumentation which would otherwise be "overdue") to February 28, 1986. Thus, with no time available to process a Technical Specification change request, the licensee properly declared the instrumentation in question to be "inoperable" effective that day. This places the Unit 2 plant in a 30 day Limiting Condition for Operation (LCO); however, since operation beyond February 28 is already prohibited (relates to electrical equipment environmental qualification issues) the subject LCO will not affect plant operation. The instrumentation in question remains functional and is operating normally.

b. The following procedures (main Control Room copies) were reviewed for clarity, technical content, consistency, and appropriate administrative controls:

1 OHP 4024.105 "Annunciator No. 5 Response Containment Spray" U-1

2 OHP 4024.205 "Annunciator No. 5 Response Containment Spray" U-2

These procedures are currently a combination of recently re-typed (perhaps word processor based) pages - each page typically addresses response to a single alarm "window" on the panel - and what appear to be repeatedly photocopied pages. Several of the pages in each procedure suffer from poor legibility. The Unit 1 procedure currently has seven effective change sheets, while the Unit 2 procedure has only three. Finally, an obvious typographical error (e.g., high spent fuel pool temperature alarm setpoint at 18025 degrees) on "drop 28" of the Unit 1 procedure had been corrected to 125 degrees (handwritten "correction"). The corresponding Unit 2 setpoint was identified as 124 degrees. Alarms on another panel (each Unit) also covering fuel pool high temperature - and there is but one pool - identify the alarm setpoint as 125 degrees. Each of these minor matters was discussed with the procedure co-ordinator who is taking action to address them. The inspector specifically checked procedure cross-references to Technical Specifications for accuracy and found all were accurate.

c. Observations were made involving plant personnel access controls utilizing newly-arrived and more modern automated metal detection equipment at the main access control point. The new equipment appeared substantially superior to that it replaced.

d. Preliminary conduit layout work to support planned implementation, during the upcoming Unit 2 outage, of RFC 2808, (replacement of control room instrument distribution panels) utilizing Job Order 43573, was briefly observed.

No violations or deviation were identified.

8. Open Items

Open Items are matters which have been discussed with the licensee, which will be reviewed further by the inspector, and which involve some action on the part of the NRC or licensee or both. Open Items disclosed during the inspection are discussed in Paragraph 5.

9. Management Interview

The inspector met with the licensee representatives (denoted in Paragraph 1.a above) following completion of the inspection on February 19, 1986. The inspection summarized the scope and findings of the inspection as described in these details.

a. The two apparent Violations were specifically discussed, including corrective actions for the first Violation as a basis for not requiring a written response (Paragraphs 2.c. and 6.).

b. The inspector advised the licensee that certain items identified as Unresolved items in Inspection Reports No. 50-31585028; 316/85028 are now to be classified as Violations. NRC will correspond further with the licensee concerning these matters at a future date (Paragraphs 2.a. and 2.b.).

The inspector also discussed the likely informational content of the report with respect to documents or processes reviewed. The licensee was afforded the opportunity to identify any such document/processes which might be proprietary, and none were so designated.