NOTICE OF VIOLATION
AND
PROPOSED IMPOSITION OF CIVIL PENALTIES

American Electric Power Service
Corporation
Indiana and Michigan Electric Company
D. C. Cook Nuclear Plant
Units 1 and 2

Docket Nos. 50-315 and 50-316
Licenses No. DPR-58 and DPR-74
EA 86-23

During four NRC inspections conducted August 9, 1985 through February 18, 1986, several violations of NRC requirements were identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," 10 CFR Part 2, Appendix C (1985), the Nuclear Regulatory Commission proposes to impose civil penalties pursuant to Section 234 of the Atomic Energy Act of 1954, as amended, ("Act"), 42 U.S.C. 2282, PL96-295, and 10 CFR 2.205. The particular violations and associated civil penalties are set forth below:

A. Technical Specification 4.6.1.2 for Unit 1, implemented by D. C. Cook Procedure 1 THP 4030 STP .202, "Containment Integrated Leak Rate Surveillance Test" requires that containment leak rates be determined in conformance with the criteria specified in Appendix J of 10 CFR Part 50. Appendix J, Paragraph III.A.1(d) requires that portions of systems penetrating containment be appropriately vented, drained or isolated during the test.

   Contrary to the above, on August 18, 1985, during performance of an integrated leak rate test (ILRT) on Unit 1 per procedure 1 THP 4030 STP .202, portions of systems penetrating containment were not appropriately vented, drained or isolated in that fifteen vents, drains, and valves as described in NRC Inspection Report 50-315/85027 were improperly aligned during the test.

B. 10 CFR Part 50, Appendix B, Criterion XIV, "Inspection, Test and Operating Status," as implemented by the D. C. Cook Operations Quality Assurance Program, Section 1.7.14, requires that measures be established for indicating the operating status of structures, systems and components, such as by tagging valves and switches, to prevent inadvertent operation.

   Contrary to the above, on August 18, 1985, and during the performance of an ILRT on Unit 1, the licensee's procedure, 1 THP 4030 STP .202, which was used to perform the test, did not require measures such as tagging valves to prevent inadvertent operation. As a result of not tagging the valves, licensee personnel repositioned eight valves after the ILRT valve lineup required by procedure was completed. The ILRT was then performed with these valves in the incorrect position.

C. Technical Specification 3.7.5.1 for Unit 2 requires the control room emergency ventilation system to be operable in Modes 1, 2, 3, and 4. Technical Specification 3.0.4 prohibits entry into an operational mode unless the conditions of the Limiting Conditions for Operations (LCO) are met without reliance on provisions contained in the action statement.

Contrary to the above, on August 19, 1985 at 0023 hours, with the control room emergency ventilation system inoperable, Unit 2 entered operational Mode 4 and by August 21, 1985 at 1401 hours, had entered Mode 1 while in the referenced action statement.

D. 10 CFR Part 50, Appendix J, Paragraph III D.2(b)(ii), as implemented by D. C. Cook Procedure 12 THP 4030 STP .204, "Personnel Air Lock Leakage and Interlock Surveillance Test," requires that whenever air locks are opened during periods when technical specifications do not require containment integrity, they shall be tested at the end of that period at a pressure equal to or greater than the calculated peak containment internal pressure related to the design basis accident (P_a).

Contrary to the above, on July 28, 1985, when the Unit 2 air lock interlock was restored after a period when containment integrity was not required by plant Technical Specifications, the licensee failed to implement Procedure 12 THP 4030 STP .204 and therefore did not test the airlock at P_a.

E. Technical Specification 3.3.2.1 for Units 1 and 2 requires that the engineered safety feature actuation system (ESFAS) instrumentation channels shall be operable with their trip setpoints consistent with the values shown in the "Trip Setpoint" column of Table 3.3-4. Table 3.3-4, Item 6b, which lists the 4 kv Bus Loss of Voltage instrument channel for the motor driven auxiliary feedwater pumps (MDAFP) requires a 3196+18, -36 volt trip setpoint with a 2±0.2 second time delay.

Technical Specification 4.3.2.1.1 for Units 1 and 2 requires that each ESFAS instrumentation channel shall be demonstrated operable by the performance of a channel calibration for the modes and at the frequencies shown in Table 4.3-2. Table 4.3-2, Item 6b, which lists the MDAFP 4 kv Bus Loss of Voltage instrument channel, requires that a channel calibration be performed at each refueling prior to operation in Modes 1, 2 and 3.

Technical Specification 4.3.2.1.3 for Units 1 and 2 require that the ESFAS response time for each ESFAS function shall be demonstrated to be within the limit at least once per 18 months.

Procedure 12 THP 6030 IMP .250, Revision 6, is the implementing document for surveillance required for the MDAFP 4 kv Bus Loss of Voltage instrumentation.

Contrary to the above, during all refuelings that occurred prior to August 23, 1985, the licensee's channel calibration surveillance procedure 12 THP 6030 IMP .250 for the Unit 1 and 2 MDAFP 4 kv Bus Loss of Voltage instrument channel was not adequate in that it did not include a calibration of the two-second time delay function.

F. Technical Specification 4.3.1.1.1 for Units 1 and 2 requires each reactor trip system instrumentation channel to be demonstrated OPERABLE by the performance of a channel calibration for the modes and frequencies shown in Table 4.3-1. Table 4.3-1, Items 7 and 8, Overtemperature Delta T and Overpower Delta T instrumentation channels respectively, requires that a channel calibration be performed at each refueling prior to operation in Modes 1 and 2.

Technical Specification 4.3.2.1.1 as implemented by procedures THP 6030 IMP .194 through IMP .197 for Units 1 and 2 requires each engineered safety feature instrumentation channel to be demonstrated operable by the performance of a channel calibration for the modes and frequencies shown in Table 4.3-2. Table 4.3-2, Item 4d, which lists the instrumentation channel for low-low average coolant temperature, requires that a channel calibration be performed at each refueling prior to operation in Modes 1, 2, and 3.

Technical Specification 4.6.4.2.b.1 for Units 1 and 2 requires the electric hydrogen recombiner (EHR) instrumentation to be demonstrated operable by the performance of a channel calibration at least once per 18 months. Procedure 12 THP 6030 IMP .140 contains the surveillance requirements for the EHR instrumentation.

Technical Specification 4.4.6.1.c. for Units 1 and 2 requires the containment humidity monitor (CHM) to be demonstrated operable by the performance of a channel calibration at least once per 18 months. Procedure 12 THP 6030 IMP .050 contains the surveillance requirements for the CHM.

Technical Specification Definition 1.9 defines a channel calibration to encompass the entire channel including the sensor.

Contrary to the above, for all refuelings prior to August 1985, the licensee's channel calibration procedures referenced above for the Overtemperature Delta T, Overpower Delta T, low-low average coolant temperature, and the electric hydrogen recombiner instrumentation channels, and the containment humidity monitor for Units 1 and 2 did not adequately demonstrate operability for the required modes in that channel calibration procedures did not include the sensors.

G. Technical Specification 4.3.1.1.1 for Unit 2 requires each reactor trip system instrumentation channel to be demonstrated operable by performance of a channel functional test for the modes and frequencies shown in Table 4.3-1. Table 4.3-1 requires that monthly channel functional tests be performed for Item 16, "Undervoltage - Reactor Coolant Pumps" and Item 17, "Underfrequency - Reactor Coolant Pumps" for operation in Mode 1 and Item 19, "Safety Injection Input from ESF" for operation in Modes 1 and 2.

Technical Specification 4.3.2.1.1 for Unit 2 requires each engineered safety feature actuation system instrumentation channel to be demonstrated operable by the performance of channel functional tests at the required frequencies and for plant operation in the modes shown in Table 4.3-2.

Table 4.3-2 for Unit 2 requires that the following monthly channel functional tests be performed:

<u>Modes 1, 2, 3, 4</u>

Item 1a	Safety Injection - Manual Initiation
Item 2a	Containment Spray - Manual Initiation
Item 3a(1)	Manual Phase A Containment Isolation
Item 3b(1)	Manual Phase B Containment Isolation
Item 3c(1)	Manual Containment Purge and Exhaust Isolation

<u>Modes 1, 2, 3</u>

Item 4a	Manual Steam Line Isolations; Item 4d, Steam Line Isolation - Steam Flow in Two Steam Lines High Coincident With Tavg Low-Low
Item 4d	Steam Line Isolation - Steam Flow in Two Steam Lines High Coincident with Tavg Low-Low
Item 5a	Turbine Trip/Feedwater Isolation-Steam Generator Water Level High-High
Item 6a	Motor Driven AFW Pump - Generator Water Level Low-Low
Item 7a	Turbine Driven AFW Pumps - Steam Generator Water Level Low-Low
Item 7b	Reactor Coolant Pump Bus Undervoltage

Contrary to the above, during testing prior to August 22, 1985, the licensee did not perform channel functional tests for the above listed instrumentation channels at the required monthly frequencies.

Collectively, these violations have been categorized as a Severity Level III problem (Supplement I).

Cumulative Civil Penalties - $100,000 assessed equally among the violations.

Pursuant to the provisions of 10 CFR 2.201, Indiana and Michigan Electric Company is hereby required to submit to the Director, Office of Inspection and Enforcement, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555 with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region III, 799 Roosevelt Road, Glen Ellyn, IL 60137, within 30 days of the date of this Notice, a written explanation or statement, including for each alleged violation: (1) admission or denial of the alleged violation, (2) the reasons for the violation if admitted, (3) the corrective steps that have been taken and the results achieved, (4) the corrective steps which will be taken to avoid further violations, and (5) the date when full compliance will be achieved. If an adequate reply is not received within the time specified in the Notice, the Director, Office of Inspection and Enforcement, may issue an order to show cause why the license should not be modified, suspended, or revoked or why such other action, as my be proper, should not be taken. Consideration may be given to extending the response time for good cause shown. Under the authority of Section 182 of the Act, 42 U.S.C. 2232, this response shall be submitted under oath or affirmation.

Within the same time as provided for the response required above under 10 CFR 2.201, Indiana and Michigan Electric Company may pay the civil penalties by letter addressed to the Director, Office of Inspection and Enforcement, with a check, draft, or money order payable to the Treasurer of the United States in the cumulative amount of One Hundred Thousand Dollars ($100,000) or may protest imposition of the civil penalties in whole or in part by a written answer addressed to the Director, Office of Inspection and Enforcement. Should Indiana and Michigan Electric Company elect to file an answer in accordance with 10 CFR 2.205 protesting the civil penalties, such answer may: (1) deny the violations listed in this Notice in whole or in part, (2) demonstrate extenuating circumstances, (3) show error in this Notice, or (4) show other reasons why the penalties should not be imposed. In addition to protesting the cumulative civil penalties in whole or in part, such answer may request remission or mitigation of the penalties. In requesting mitigation of the proposed penalties, the five factors addressed in Section V.B of 10 CFR Part 2, Appendix C (1985) should be addressed. Any written answer in accordance with 10 CFR 2.205 should be set forth separately from the statement or explanation in reply pursuant to 10 CFR 2.201, but may incorporate statements or explanations by specific reference (e.g., citing page and paragraph numbers) to avoid repetition. Indiana and Michigan Electric Company's attention is directed to the other provisions of 10 CFR 2.205, regarding the procedure for imposing civil penalties.

Upon failure to pay any civil penalties due which has been subsequently determined in accordance with the applicable provisions of 10 CFR 2.205, this matter may be referred to the Attorney General, and the penalty, unless compromised, remitted, or mitigated, may be collected by civil action pursuant to Section 234c of the Act, 42 U.S.C. 2282.

FOR THE NUCLEAR REGULATORY COMMISSION

James G. Keppler

James G. Keppler
Regional Administrator

Dated at Glen Ellyn, Illinois
this 26th day of March 1986

U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-315/85027

Docket No. 50-315

License No. DPR-58

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

Facility Name: D. C. Cook Unit 1

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

Inspection Conducted: August 27 and September 3, 1985

Carl J Paperiello

Inspector: for W. G. Guldemond

9/11/85
Date

Carl J Paperiello

Approved By: L. A. Reyes, Chief
for Operations Branch

9/11/85
Date

Inspection Summary

Inspection on August 27 and September 3, 1985 (Report No. 50-315/85027(DRS)

Areas Inspected: Special announced safety inspection of the events resulting in incorrect system lineups to support a containment integrated leak rate test. The inspection involved four inspector-hours onsite by one inspector and five inspector-hours conducting in-office review.

Results: In the area inspected, one apparent violation was identified regarding failure to control a test boundary - Paragraph 2.

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DETAILS

1. Persons Contacted

American Electric Power Service Corporation

*W. G. Smith, Jr., Plant Manager
-A. A. Blind, Assistant Plant Manager - Maintenance
+*K. R. Baker, Operations Superintendent
C. E. Murphey, Production Supervisor - Operations
M. A. Baken, Department Assistant, Quality Control
C. A. Ross, Staff Engineer
J. R. Sampson, Production Supervisor - Operations
+P. A. Barrett, Lead Compliance Engineer
J. G. Feinstein, Manager, Nuclear Safety and Licensing
R. F. Kroeger, Manager of Quality Assurance
+D. S. Klimer, Performance Engineer
+R. Czajka, Performance Engineer
M. W. Evarts, Nuclear Safety and Licensing
M. S. Ackerman, Nuclear Safety and Licensing
+T. K. Postelwait, Performance Engineering Supervisor
+L. S. Gibson, Technical Engineering Superintendent

NRC

B. Jorgensen, Senior Resident Inspector
J. Heller, Resident Inspector
C. Wolfsen, Resident Inspector

*Denotes those personnel in attendance at the exit meeting on August 27, 1985.

+Denotes those personnel participating in the meeting held on August 27, 1985 to discuss the licensee's investigation.

2. Containment Integrated Leak Rate Test (CILRT) Boundary Control

On August 18, 1985, during the performance of a CILRT on D. C. Cook Unit 1, a Region III inspector discovered several containment penetrations that were not vented as specified by the test procedure. As discussed in Inspection Report 50-315/85025(DRS), this was immediately brought to the attention of the licensee. In response to this identified problem, the licensee rechecked those portions of the CILRT test boundary outside containment for correct alignment (without verification) and discovered the following discrepancies:

Valve No.	Description	Required Condition	As Found Condition
IPX-6	Safety Injection Accumulator Sample	Open, uncapped	Closed, capped

NPX-106	Hot Leg Sample	Open, uncapped	Closed, capped
NPX-108	Pressurizer Liquid Sample	Open, uncapped	Closed, capped
EPX-10	Hydrogen Sample	Open, uncapped	Closed, capped
GPX-312	Nitrogen Isolation to Accumulator Test	Open, gauge removed	Closed, gauge installed*
GPC-310	Nitrogen Supply to the Reactor Coolant Drain Tank	Open, line vented	Open, line intact*
XPX-100	Control Air Vent	Open, gauge removed	Open, gauge installed*
BD-103-1	Steam Generator	Open	Closed
BD-103-2	Blowdown	Open	Closed
BD-103-3	Isolation	Open	Closed
BD-103-4	Valves	Open	Closed
NS-344	Hydrogen Sample System Supply Valve	Closed	Open
NS-326	Hydrogen Sample Return Vent	Open	Closed
NS-346	Hydrogen Sample	Closed	Open
NPX-110	Pressurizer Steam Space Sample	Open	Closed

a. *These discrepancies were identified initially by the NRC Region III inspector.

As a result of these discrepancies, the following actions were taken and commitments made:

(1) All discrepant boundary conditions were corrected and independently verified with the exception of the steam generator blowdown isolation valves which are not technically boundary valves. This was verified by the inspector who initially discovered the alignment problem.

(2) The CILRT was reperformed. This was witnessed by the inspector who initially discovered the alignment problem.

(3) The licensee committed to check those portions of the test boundary inside containment for correct alignment following the CILRT.

(4) An investigation as to the cause of the problem was initiated.

b. Subsequent to containment depressurization, the following discrepancies were discovered on those portions of the test boundary inside containment:

Valve No.	Description	Required Condition	As Found Condition
SI-164-1	No. 1 Safety Injection Accumulator Vent	Open	Closed
SI-164-4	No. 4 Safety Injection Accumulator Vent	Open	Closed
NPX-300	Nitrogen Supply to the Pressurizer Relief Tank	Open, vent plug removed	Open, plug installed

As a result of these additional discrepancies, the licensee performed a local leak rate test on the penetration associated with NPX-300, took a penalty on the CILRT results, and performed an evaluation which demonstrated that misalignment of the accumulator vent valves did not have a significant impact on the CILRT results. These actions will be discussed further in Inspection Report 50-315/85025(DRS).

c. On August 27, 1985, the inspector had a meeting with those personnel identified in Paragraph 1 of this report to review the results of the licensee's investigation and planned corrective actions. At this meeting the licensee identified three root causes associated with the incorrect test boundary configuration:

(1) The test boundary valve lineup procedure was deficient in that it failed to clearly specify the removal of such components as pipe caps, pipe plugs, and gauges in addition to valve manipulations to ensure that lines were adequately vented as required. This deficiency was compounded by the fact that operations personnel perform valve manipulations and pipe cap removal but do not normally remove pipe plugs or gauges or disconnect mechanical fittings. Thus, not only were certain specific required actions not explicitly identified, responsibility for completing those actions was not clearly identified.

(2) Valve positions were not adequately controlled by tagging or other means following completion of the boundary valve lineup. The following boundary valves were manipulated after the boundary lineup was performed:

(1) EPX-10
(2) BD-103-1, 2, 3, 4
(3) NS-344
(4) NS-326
(5) NS-346

These manipulations were made as part of routine activities not associated with the CILRT without informing either the operations shift supervisor or CILRT personnel.

(3) Personnel error on the part of certain personnel in incorrectly establishing and verifying the CILRT boundary configuration. This causal factor was based on two facts:

    (a) No evidence existed that would indicate that the subject portions of the boundary were manipulated following the initial lineup.

    (b) The same two individuals, a reactor operator and senior reactor operator, had initialled the CILRT valve lineup sheet for checking and independently verifying the position of all valves subsequently found mispositioned and for which no documentation of post-lineup manipulation existed.

d. As a result of questions asked by the inspector during the meeting, the following information came to light:

    (1) Personnel performing the valve lineups received no pre-lineup briefings.

    (2) The licensee does not have a procedure or provide formal training on how to perform valve lineups. Thus, consistent guidance on such things as reliance on local and remote position indication or valve stem position is lacking.

    (3) Four of the five mispositioned valves outside containment for which no documentation of post-lineup manipulation existed were local chemistry sample points not routinely operated by operations personnel.

    (4) The remaining value outside containment found mispositioned, GPX-312, and the two accumulator vent valves inside containment found mispositioned were associated with an ongoing accumulator level transmitter replacement program which was continued up to the start of the CILRT.

    (5) Additional controls on containment access were not imposed following completion of the valve lineup. A significant in-containment cleanup effort was conducted after the lineup.

    (6) The two operators who were associated with a number of the mispositioned valves steadfastly maintained that they had checked all the valves for which they initialled on the lineup sheets. They admitted that, in hindsight, they had not complied with the literal requirements for time and space separation on independent verification.

    (7) Quality Control personnel did not provide extensive coverage of CILRT activities, including valve lineups.

e. Following the August 27, 1985 meeting, the inspector reviewed the licensee's procedures for independent verification and the CILRT to determine what impact those procedures had on this event. The following observations were made.

(1) The independent verification requirements contained in Section 3.8 of PMI-4010 are adequate.

(2) The only Quality Control signature requirements in the CILRT procedure, 1 THP 4030 STP.202, are for removal of fire extinguishers from containment prior to the test and restoration following the test.

(3) Step 4.31 of the CILRT requires that the Chemical Supervisor be informed of all sampling valves which cannot be operated during the test.

(4) The valve lineup sheets contained in the CILRT procedure only specify valve positions. They do not specify pipe plug or cap removal, gauge removal, or line disconnects.

(5) The CILRT procedure does not require tagging boundary valves to prevent inadvertent operation.

f. Based on the above information, the following conclusions were reached by the inspector concerning the CILRT boundary and misconfiguration at D. C. Cook:

(1) As concluded by the licensee, the misconfiguration was primarily the result of two factors:

(a) The licensee failed to establish and maintain control of the CILRT boundary by any viable mechanism such as tagging. This permitted post-lineup boundary manipulation. Further, the requirements of Step 4.31 of the CILRT procedure were not effectively implemented as evidenced by the fact that the chemistry department did manipulate certain sample valves.

(b) The boundary lineup sheets are inadequate in that they do not clearly specify removal of devices necessary to ensure proper venting.

These two conditions appear to be violations of NRC requirements.

While it is certain that personnel error contributed to this event, the information available does not support a clear determination of who made the error(s).

(2) The problem was exacerbated by a failure to effectively communicate to all station personnel that CILRT boundaries had been established and that any boundary manipulated required prior approval.

(3) In addition to the conclusions above, the following weaknesses in licensee performance were noted:

   (a) Personnel responsible for performing the CILRT valve lineups were not adequately briefed on their responsibilities.

   (b) The extent of Quality Control involvement in test oversight was minimal.

   (c) No procedure exists defining how valve position verifications are to be conducted.

   It was noted that the licensee aggressively pursued this event and evidenced a strong positive attitude toward safety when deciding to reverify the entire CILRT boundary configuration and re-perform the CILRT upon discovery of lineup problems. Additionally, by the time of the August 27, 1985 meeting, the licensee had already concluded that the CILRT procedure required revision to include more explicit instructions on test boundary lineup and control.

3. Exit Interview

The inspector met with the personnel identified in Paragraph 1 on August 27, 1985 to discuss the findings of this inspection. The licensee acknowledged those findings. On September 3, 1985, the inspector confirmed those findings with the licensee telephonically after reviewing the CILRT and independent verification procedures. The inspector also discussed the likely informational content of the inspection report with regards to documents reviewed by the inspector during the inspection. The licensee did not identify any such documents as proprietary.

OFFICE OF INSPECTION AND ENFORCEMENT
DIVISION OF INSPECTION PROGRAMS

Report: 50-315/85-28; 50-316/85-28

Docket: 50-315; 50-316

Licensee Nos: DPR-58; DPR-74

Licensee: American Electric Power Service Corporation
Indiana and Michigan Electric Company
Columbus, Ohio 43216

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

Inspection at: Donald C. Cook Site, Bridgman, Michigan

Inspection Conducted: August 19-28, 1985

Inspectors: James P Kearney 9/23/85
J. P. Kearney, IE, Team Leader Date

Scott Alexander McNeil 9/23/85
S. A. McNeil, ORPB, IE Date

R. W. Cooper, II 9/23/85
R. W. Cooper, II, ORPB, IE Date

P F McKee 9/23/85
P. F. McKee, Chief, Operating Reactors Program Branch, IE Date

Inspection Summary

Areas Inspected: This special unannounced safety inspection involved 250 hours on site in the areas of plant operations and surveillance programs for the reactor trip system, auxiliary feedwater system, and the engineered safety feature actuation system channel functional tests.

Results: Five potential enforcement findings, referred to an unresolved items in the report, were identified during the inspection. These items will be followed up by the NRC Region III office.

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DETAILS

1. Persons Contacted

Licensee

*K. Baker, Operations Superintendent
*P. Barrett, AEPSC - Nuclear Safety and Licensing
*A. Blind, Assistant Plant Manager - Maintenance
M. Camp, Operations Walkdown Coordinator
*G. Caple, Assistant Supervisor - Quality Control
N. Daavettila, Performance Engineer - Maintenance
*M. Evarts, AEPSC Nuclear Safety and Licensing
*J. Feinstein, AEPSC - Manager Nuclear Safety and Licensing
*L. Gibson, Technical Superintendent - Engineering
P. Helms, Control and Instrument Assistant Supervisor
R. Holder, Performance Engineer-Control and Instrument
*M. Horvath, Quality Assurance Supervisor
T. Johnson, Performance Engineer-Maintenance
*R. Kroeger, Quality Assurance Manager
C. Miles, Control and Instrumentation Supervisor
*C. Murphy, Production Supervisor
*R. Simms, Shift Technical Advisor
*W. Smith Jr., Plant Manager
R. Stevens, Performance Engineer-Operations
*B. Svensson, Assistant Plant Manager-Operations
M. Thornburg, Instrument Maintenance Supervisor
T. Turner, Performance Engineer-Control and Instrument
G. Wallace, Performance Engineer-Control and Instrument

NRC

*W. Guildemond, Region III
J. Heller, Resident Inspector
*B. Jorgensen, Senior Resident Inspector
*P. McKee, IE
*C. Norelius, Region III
*C. Wolfsen, Resident Inspector

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* Attended exit interview

2. Review of Plant Operations

a. Operational Safety Verification

The control room was inspected periodically to verify compliance with minimum staffing requirements, access control, adherence to approved procedures, and compliance with limiting conditions for operation (LCOs). Reviews were made of plant operator logs, tagging requests, standing orders, and bypass logs. Two shift turnovers were also observed.

No violations or deviations were identified.

b. Station Tours

The inspectors toured accessible areas of the plant including the control room, Unit 2 switchgear room, and the Unit 2 auxiliary feedwater (AFW) system. During these tours, observations were made relative to equipment condition, fire and safety hazards, use of procedures, radiological controls and conditions, housekeeping, and ongoing surveillance activities.

Combustible material including plywood and yellow polyethylene sheeting was found stored in the passageway between the Unit 1 and Unit 2 control rooms. The licensee removed the materials when notified by the inspectors.

c. System Walkdown

The inspectors conducted a walkdown of the Unit 2 turbine driven AFW pump train of the AFW System to observe equipment conditions and valve positions.

No violations or deviations were identified.

3. Surveillance Activities

The inspectors reviewed the licensee's surveillance programs for the reactor trip system (RTS), the AFW system, and the engineered safety feature actuation system (ESFAS) channel functional tests. The inspectors also witnessed the performance of surveillance procedure 2 THP 4030 STP.145, "Reactor Logic Train 'A' and 'B' and Reactor Trip Breakers 'A' and 'B'," revision 4. The following concerns were identified on Unit 2; however, many were also applicable to Unit 1.

a. The inspectors found that the channel functional test (CFT) for the RTS safety injection input from ESF required by Technical Specification (TS) 4.3.1.1.1, Table 4.3-1, Item #19 was being performed for each train every other month (e.g., train A: May 21, 1985 and July 16, 1985; train B: June 18, 1985 and Aug. 15, 1985) vice every month as required. The licensee was informed of this finding at 2:20 p.m. on August 22, 1985 and immediately declared the train A instrument inoperable. The licensee demonstrated the instrument was operable by the performance of procedure 2 THP 4030 STP.145 within the six hour Action Statement requirement of the LCO associated with TS 4.3.1.1.1. The inspectors observed the performance of this surveillance procedure. Further inspector review revealed that procedure 2 THP 4030 STP.145 was also used to perform the logic and relay portions of the CFTs for the following TS line items:

TS Surveillance		Applicable Modes
TS 4.3.1.1.1, Table 4.3-1 (RTS instrumentation) Items		
#16	"Undervoltage - Reactor Coolant Pumps"	1
#17	"Underfrequency - Reactor Coolant Pumps"	1
#19	"Safety Injection Input from ESF"	1,2
TS 4.3.2.1, Table 4.3-2 (ESFAS instrumentation) Items		
#1a	"Safety Injection-Manual Initiation"	1,2,3,4
#2a	"Containment Spray - Manual Initiation"	1,2,3,4
#3a1	"Manual Phase A Containment Isolation"	1,2,3,4
#3b1	"Manual Phase B Containment Isolation"	1,2,3,4
#3c1	"Manual Containment Purge and Exhaust Isolation"	1,2,3,4
#4a	"Manual Steam Line Isolation"	1,2,3
#4d	"Steam Line Isolation - Steam Flow in Two Steam Lines High Coincident with Tavg Low-Low"	1,2,3
#5a	"Turbine Trip/Feedwater Isolation - Steam Generator Water Level High-High"	1,2,3
#6a	"Motor Driven AFW Pumps - Steam Generator Water Level Low-Low"	1,2,3
#7a	"Turbine Driven AFW Pumps-Steam Generator Water Level Low-Low"	1,2,3
#7b	"Reactor Coolant Pump Bus Undervoltage"	1,2,3

These TS surveillances also are required to be performed every month for each train while in the applicable modes of operation. This procedure was only performed for a particular train every other month. Therefore, the erroneous frequency of performance of this procedure resulted in numerous instances where the surveillances to demonstrate the operability of the RTS and ESFAS channels (listed above) were not performed at the required frequency while Unit 2 was in either modes 1, 2, or 3 and during many startups.

b. The potential existed for failing to demonstrate the operability of the reactor trip breakers at the proper frequency. TS 4.3.1.1.1, Table 4.3-1, Item #2 requires that the reactor trip breakers be demonstrated operable monthly by performing a CFT for each train (A or B) on an alternating month basis. Procedure 2 THP 4030 STP.144, "Reactor Trip Breakers Surveillance Test," revision 0, was used to satisfy this TS requirement and did not differentiate between the A and B trains. The Nuclear Test Schedule system scheduled this procedure to be done every month; however, did not specify which train (A or B) was due. The determination of which train to test was left up to the Control and Instrument (C&I) technician performing the test or the C&I surveillance test scheduler. In fact, the inspectors found that train A was tested for two consecutive months (July 17, 1984 and August 14, 1984) without testing train B until September 11, 1984. This frequency didn't exceed the maximum allowable interval of two months (±25%) because both trains A and B were tested during the performance of the startup test procedure 2 THP 4030 STP.180, "SU(1) Instrumentation Checks Prior to Start-up," revision 2, on June 30, 1984. Although the surveillance interval was not exceeded, the inspectors were concerned that the potential did exist for a TS violation.

c. Unit 2 TS 3.3.2.1 requires that the ESFAS channels and interlocks shown in Table 3.3-3 be operable with trip setpoints consistent with the values shown in Table 3.3-4. Item 6.b of Table 3.3-3 requires that the motor-driven auxiliary feedwater pump (MDAFP) 4 KV bus loss of voltage automatic start actuation channels be operable when in modes 1, 2, or 3. To demonstrate operability, the voltage and time delay relay setpoints must be shown to be within the allowable values of 3196, + 18, - 36 volts with a 2 ± 0.2 second delay as stated in Item 6.b. of Table 3.3-4. TS 4.3.2.1.3 requires that this function be demonstrated operable by the performance of a channel calibration every 18 months.

Procedure 12 THP 6030 IMP.250, "4KV Diesel Start, 4KV ESS Bus Undervoltage, 34.5 KV Bus Undervoltage, and 600 Volt Bus Undervoltage Relay Calibration," revision 6, was used to perform the channel calibration described above. This procedure verified the proper voltage setpoint, but did not check the setpoint of the 2 second time delay relay. Failure to check the time delay relay setpoint violated T.S. 4.3.2.1.3. As a result, Unit 2 operated above mode 4 without demonstrating the operability of both Unit 2 MDAFP 4KV bus loss of voltage automatic start actuation channels. Since ESFAS automatic start of the unit's two MDAFPs cannot be ensured, the operability of both pumps was not adequately demonstrated. This resulted in plant operation above mode 4 while outside of the LCO stated in TS 3.7.1.2.

The licensee was informed of this condition and began implementing the actions required by TS 3.0.3 at 4:00 p.m. on August 23, 1985. At this time, Unit 2 was in mode 1 and Unit 1 was shutdown. The licensee commenced drafting and approving a temporary procedure for calibrating the subject time delay relays. This surveillance test procedure was performed by the licensee on Unit 2 and completed satisfactorily at 8:45 p.m. on August 23, 1985. The Unit 2 time delay relays were declared operable, and the NRC was notified.

d. TS 1.9 states, "... the channel calibration shall encompass the entire channel including the sensor and alarm and/or trip functions...." For several channel calibrations, the licensee was not performing a check of the related sensors. Three specific examples were:

(1) TS 4.3.1.1.1, Table 4.3-1, Items 7 and 8 and TS 4.3.2.1.1, Table 4.3-2, Item 4.d require the calibration of the unit's four $\Delta T/T_{avg}$ Protection Set Channels at 18 month intervals. This is performed to demonstrate the operability of the over-temperature ΔT and the overpower ΔT RTS channels and the operability of the ESFAS channels for the steam line isolation-high steam flow in two steam line channels concident with T_{avg} low-low. TS 3.3.1.1 and TS 3.3.2.1 require that these RTS channels be operable above mode 3 and that these ESFAS channels be operable above mode 4, respectively. Procedures 2 THP 6030 IMP.194 through IMP.197 ($\Delta T/T_{avg}$ Protection Set Calibrations) used a calibration method that disconnected the leads to the reactor coolant system resistance temperature detectors (RTDs) and applied a test signal to the output leads downstream of the RTDs. These tests did not check the actual sensors, the RTDs, that generate the source signals used by the downstream circuitry. This was the only method of calibration used on these channels since preoperational testing was completed.

(2) TS 4.6.4.2.b.1. requires calibration of electric hydrogen recombiner instrumentation at 18 month intervals to demonstrate the operability of the hydrogen recombiner system. TS 3.6.4.2 requires that two independent containment hydrogen recombiner systems be operable above mode 3. Procedure 12 THP 6030 IMP.140, "Electric Hydrogen Recombiner Instrumentation Calibration," revision 3, used a calibration methodology that disconnected thermocouple leads and applied test signals to the output leads to calibrate the downstream temperature indicators. This test did not check the actual sensors, the thermocouples, that generate the source signal received by the downstream circuitry and indicators. The licensee has used this methodology since the calibration was first performed on each unit's respective systems.

(3) TS 4.4.6.1.c requires that the containment humidity monitor, if being used, be calibrated at least once per 18 months to verify the operability of the leakage detection systems. The leakage detection systems are required to be operable above mode 5. Procedure 12 THP 6030 IMP.050, "Containment Humidity Detector Calibration," revision 2, did not check the sensor, the humidity detector.

Because of the conditional nature of the surveillance requirement (i.e., "if being used"), the licensee's failure to calibrate the humidity monitor may have never resulted in the licensee's entering the action statement associated with leakage detection system operability. On the other hand, continued failure to include a check of the humidity monitor as part of the calibration may lead to a situation where the licensee determines that the leakage detection systems are operable when, in fact, they would be considered inoperable by TS 3.4.6.1.

The failure to perform surveillance testing at the required frequency (item 3.a) and the failure to perform adequate surveillance tests (item 3.c and 3.d) will remain unresolved pending followup by the Region III office (50-315/85-28-01; 50-316/85-28-01).

e. TS 1.9 requires that a channel calibration include the CFT. Procedure PMI 6030, "Instrument and Control; Maintenance and Calibration," revision 4, section 3.2.8.19.1, states that whenever a reactor protection instrument maintenance procedure (e.g., calibration) is completed, the reactor protection channel shall not be declared operable until a CFT has been completed by performing the applicable reactor protection surveillance test procedure (STP). The inspector found that procedure 2 THP 6030 IMP.231 "Power Range Nuclear Instrumentation Calibration," revision 5, was performed for all four power range channels on January 21, 1985. The associated CFTs to verify these channels operable were apparently not performed until February 12, 1985. From January 21, 1985 to February 12, 1985 Unit 2 operated in mode 1 above 85% rated thermal power (RTP). TS 3.3.1.1, Table 3.3-1, Item 2 states that an inoperable power range neutron flux channel must be placed in the tripped condition within 1 hour. In addition, with less than four channels operable, thermal power must be restricted to ≤75% of RTP and the neutron flux setpoint reduced of ≤85% of RTP within four hours; or, the quadrant power tilt ratio must be monitored at least once per 12 hours.

   The apparent failure to demonstrate power range neutron flux channel operability after calibration while operating in mode 1 shall remain unresolved pending followup by the NRC Region III office (50-315/85-28-02; 50-316/85-28-02).

f. The master surveillance test requirements matrix, contained in PMI 4030, "Technical Specifications," revision 8, was incomplete and in some instances did not list the proper surveillance procedures. For example, PMI 4030 did not list 2 THP 4030 STP.145 as the CFT procedure for items 16, 17, and 19 of Table 4.3-1 (RTS instrumentation) and items 1.a, 2.a, 3.a.1, 3.b.1, 3.c.1, 4.a, 5.a, 6.a, 7.a, and 7.b of Table 4.3-2 (ESFAS instrumentation).

4. TS 6.8.3 allows temporary changes to procedures to be made provided that the intent of the original procedure is not altered; the change is approved by the two members of plant management, at least one of whom holds a senior reactor operator license; the change is documented, reviewed, and approved by the plant manager within 14 days of implementation.

Contrary to the above, Control and Instrument (C&I) technicians made changes to STPs without obtaining review and approval by plant management before implementation or plant manager review and approval within 14 days. The inspectors found 11 STPs where changes were made without the proper review and approval. Interviews with C&I technicians revealed that it was a common practice in the C&I department to modify a procedure without writing a temporary change to the procedure. In addition, C&I supervisors failed to initiate corrective action to revise these STPs during their review of completed surveillance tests.

The failure to adequately review temporary procedure changes and the failure to determine the implications of such changes on the validity of previous surveillance tests will remain unresolved pending followup by the Region III office (50-315/85-28-03; 50-316/85-28-03).

5. TS 6.8.1.a states that written procedures shall be established, implemented, and maintained for applicable procedures recommended in Appendix A of Regulatory Guide (RG) 1.33, November 1972. RG 1.33, section H.2 requires specific procedures for surveillance tests, inspections, and calibrations.

Procedure 12 THP 6030 IMP.062, "Protection System Bistable Adjustment/ Replacement Procedure," revision 0, states that when performing an STP, a bistable found to be out of specification may be adjusted using the STP to bring the trip and reset values within specification. In addition, the person performing the initial STP review for channel operability shall review the data for all adjusted bistables to determine if portions of the system calibration are required to be performed. This review is to be recorded on the "Signoff Sheet" of this procedure. The "Signoff Sheet" is to be filed with STP records. Also, the out of specification information on the applicable bistables is to be recorded and tracked on the"Bistable Reguiring Adjustment" sheet. Any bistable requiring adjustment twice is to be replaced.

The inspector found that seven bistables were adjusted during July 1985 in the following STPs:

2 THP 4030 STP.107	"Overtemperature and Overpower Protection Set IV Surveillance Test (monthly)"
2 THP 4030 STP.111	"Pressurizer Pressure Protection Set I Surveillance Test"
2 THP 4030 STP.112	"Pressurizer Pressure Protection Set III Surveillance Test"
2 THP 4030 STP.117	"Steam Generator Level Protection Set III Surveillance Test"
2 THP 4030 STP.119	"Steam Generator 1 and 2 Mismatch Protection Channel Set I Surveillance Test"

Interviews with C&I Supervisors and a review of records revealed that neither the "Signoff Sheets" nor the "Bistable Requiring Adjustment" records were performed. The failure to adequately implement procedure 12 THP 6030 IMP.062 shall remain unresolved pending followup by the NRC Region III office (50-315/85-28-04; 50-316/85-28-04).

6. On January 13, 1985 at 7:45 p.m. Unit 2 quadrant power tilt was determined to be greater than 1.02 (actual value was 1.023). This put the unit in the action statement for TS 3.2.4. The power range neutron flux-high trip and reset setpoints were required to be lowered at least 3% power for every 1% of indicated quadrant power tilt above 1.0 within 6 hours.

   The licensee wrote an emergency job order (#16021) to lower the applicable trip and reset setpoints each by 9% power. From 10:30 p.m. to 11:27 p.m. the setpoints were reset and recorded as reset using the following CFT procedures for each power range channel:

2 THP 4030 STP.127	"Power Range Nuclear Instrumentation Protection Set I N-41," revision 4
2 THP 4030 STP.128	"Power Range Nuclear Instrumentation Protection Set II N-42," revision 4
2 THP 4030 STP.129	"Power Range Nuclear Instrumentation Protection Set III N-43," revision 4
2 THP 4030 STP.130	"Power Range Nuclear Instrumentation Protection Set IV N-44," revision 4

   At 2:38 p.m. on January 14, 1985 the licensee commenced lowering reactor power at 15% per hour from 82% RTP to ≤50% RTP to comply with the action statement. The statement requires reactor power to be ≤50% RTP within 24 hours of exceeding the quadrant power tilt limit if the quadrant power tilt ratio has not been verified to be within its limit. The quadrant power tilt at 12:15 p.m. was 1.0223. At 4:32 p.m., the quadrant power tilt finally returned to within its limits at 1.006. The licensee attributed the cause of the out of limit condition to power range channel N-41 lower detector drift. No immediate corrective action for N-41 was taken. Power reduction was stopped at 4:33 p.m. and Unit 2 commenced raising power at 2% per hour to >90% RTP.

   At 5:32 p.m., the CFTs for all four power range channels were commenced, without a job order, to reset the trip and reset setpoints of the neutron flux-high trip to 109% and 107%, respectively. The CFTs were completed at 6:30 p.m. The completed procedures showed that these trips were found to be at 109% and 107% and not at 100% and 98%, as was expected. This inconsistency was not noted by either the technicians involved, the SRO, or the Instrument Maintenance Supervisor reviewing the completed test.

   The inspector interviewed the technicians involved in setting the neutron flux-high setpoints on January 13 and 14, 1985. The technicians involved with resetting the neutron flux-high setpoints on January 14 stated that they found them at 109% and 107% RTP. However, the technicians responsible for lowering these setpoints on January 13 stated that they correctly lowered the applicable setpoints.

On January 15, 1985 Unit 2 was operating at >90% RTP and continued to do so through January 21, 1985 when the licensee calibrated all 4 power range channels (see item 3.e).

The inspectors had the following concerns that will remain unresolved pending followup by the NRC Region III office (50-316/85-28-05):

a. The licensee's performance of the action to reduce trip and reset setpoints is in doubt.

b. Procedure PMI-6030 permits the adjustment of bistable setpoints through use of the associated STP (i.e., CFT) procedure if the bistable was found to be out of specification during the performance of the CFT. The neutron flux-high bistable setpoints were not found out of specification during the CFT. Rather, these setpoints were required to be adjusted because of a TS action statement and so, should have been reset utilizing the appropriate channel calibration procedures.

c. TS 3.2.4 also requires that the cause of the out-of-limit quadrant power tilt condition be identified and corrected prior to increasing thermal power. The cause was identified as power range channel N-41 drift, but the channel was not calibrated until 7 days after increasing power from 50% to >90% RTP. If power range N-41 was the cause of the quadrant power tilt being out of its limit, then the operability of N-41 is in question.

7. Unresolved and Open Items:

An unresolved item is a matter about which more information is required to determine whether it is an acceptable item, a deviation, or a violation. The following unresolved items will be followed up by the NRC Region III office:

Unresolved Item 50-315/85-28-01; 50-316/85-28-01. The failure to perform surveillance testing at the required frequency and the failure to perform adequate surveillance testing (Items 3.a, 3.c, and 3.d).

Unresolved Item 50-315/85-28-02; 50-316/85-28-02. The failure to conduct a channel functional test following a channel calibration (Item 3.e).

Unresolved Item 50-315/85-28-03; 50-316/85-28-03. The failure to adequately review temporary procedure changes and the implications of such changes on the validity of previous surveillance tests (Item 4).

Unresolved Item 50-315/35-28-04; 50-316/85-28-04. The failure to adequately implement procedure 12 THP 6030 IMP.062 (Item 5).

Unresolved Item 50-316/85-28-05. The determination of the sequence of events surrounding the period January 13-14, 1985 (Item 6).

8. Exit Interview

The findings of this inspection were discussed with the persons designated in paragraph 1 on August 28, 1985.

U. S. NUCLEAR REGULATORY COMMISSION
REGION III

Reports No. 50-315/85029(DRP); 50-316/85029(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: September 3, 1985 through September 30, 1985

Inspectors: B. L. Jorgensen

J. K. Heller

C. L. Wolfsen

Approved By: C. W. Hehl, Chief
Projects Section 2A CW Hehl 10/25/85
Date

Inspection Summary

Inspection on September 3, 1985 through September 30, 1985 (Reports No. 50-315/85029(DRP); 50-316/85029(DRP))

Areas Inspected: Routine unannounced inspection by the resident inspectors of licensee actions on previous inspection findings; operational safety verification; surveillance; maintenance; Confirmatory Action Letter; regional requests; and licensee event reports. The inspection involved a total of 224 inspector-hours by three NRC inspectors including 25 inspector-hours off-shift.

Results: Of the seven areas inspected, no violations or deviations were identified in six areas, while two violations were identified in the remaining area (Unit startup and operation with required safety equipment not operable - Paragraph 4.a; inadequate containment air lock test - Paragraph 4.c). System testing to demonstrate/maintain required operability status is an area of concern relating to both violations. Until further evaluation can be done in the area of establishing and controlling special plant conditions or prerequisites, that area continues to be of concern as well. This inspection found no additional problems in the areas of flammable materials control and test documentation processes, though continued indications of "casual" documentation practices were seen in another recent inspection and cannot yet be de-emphasized.

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DETAILS

1. Persons Contacted

* * W. G. Smith, Jr., Plant Manager
* * B. Svensson, Assistant Plant Manager
* T. Kriesel, Technical Superintendent - Physical Science
* * A. Blind, Assistant Plant Manager
* * K. Baker, Operation's Superintendent
* * J. Stietzel, Quality Control Superintendent
* T. Beilman, Planning Supervisor
* J. Allard, Maintenance Superintendent
* * L. Gibson, Technical Superintendent - Performance
* E. Murphy, Production Supervisor
* G. Caple, Administrative Compliance Coordinator - Quality Control Department
* * J. Sampson, Production Supervisor

The inspector also contacted a number of licensee and contract employees and informally interviewed operation, technical and maintenance personnel during this period.

*Denotes personnel attending exit interview on October 1, 1985.

2. Licensee Actions on Previously Identified Items

a. (Closed) Violations (315/84-19-03; 316/84-21-03): Acceptance criteria were not included in applicable procedures to perform certain instrument channel checks. The licensee's letter (AEP:NRC:0915) dated January 11, 1985 committed to revision of the cited procedures. These actions have been accomplished, verified and the verification documented in QC Surveillance Report QCO-85-0217.

b. (Closed) Open Items (315/84-19-02; 316/84-21-02): Procedures for RHR surveillance testing needed revision to assure mini-flow valve circuitry is properly challenged. The procedures have been revised in such a way as to eliminate this concern, the revision verified, and documentation filed as QC Surveillance Report QCO-85-0407.

c. (Closed) Open Items (315/84-19-05; 316/84-21-05): Adequacy of shiftly checks of auxiliary feedwater trip and throttle valve position for assuring pump/turbine operability. The problems in maintaining the valve "latched" which originated this concern have not recurred.

d. (Open) Confirmatory Action Letter (315/85022-03; 316/85022-03): See Paragraph 6.a. for a discussion of this item.

e. (Open) Confirmatory Action Letter (315/85022-04; 316/85022-04): See Paragraph 6.b. for a discussion of this item.

f. (Open) Confirmatory Action Letter (315/85022-05; 316/85022-05): See Paragraph 6.c. for a discussion of this item.

No violations or deviations were identified.

3. Operational Safety Verification

a. Both units were maintained in MODE 5 (Cold Shutdown) throughout the course of this inspection. Unit 1 is in the late stages of completion of a scheduled refueling/maintenance/modification and testing outage which has been extended to correct potentially adverse seismic qualification conditions inside the containment. This is discussed further at Item f. below and will also apply to Unit 2 before restart of that plant. Unit 2 continues in an outage involving investigation and repair of primary-to-secondary leakage of steam generator tubes.

b. The inspector observed control room operation including manning, shift turnover, approved procedures and 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, Unit 1 containment, and screenhouse were made to observe accessible equipment conditions, including fluid leaks, potential fire hazards, and control of activities in progress. The inspector independently surveyed accessible areas of the auxiliary building using a Xetex 305B digital exposure rate meter (Serial number NRC 013166) and verified that the readings were in agreement with the licensee's readings and that areas were posted as required.

c. A specific cleanliness tour of the Unit 1 upper containment was conducted on September 18. Numerous items remained to be removed, repaired or secured. A list was provided to the licensee representative assigned final containment closeout responsibility. The licensee had not yet performed his own final inspections.

d. The inspector was notified on September 3, 1985 of the discovery of Unit 2 auxiliary building safeguards ventilation system damage in the form of open weld seams, leaking charcoal, and localized corrosion or water damage. This matter was referred to NRC Region III specialists who performed a review and discussed appropriate corrective actions for the specific component problems identified, and further investigations to ascertain the breadth of the problems, with licensee representatives.

Mutual understandings reached in this matter are documented in IE Inspection Reports No. 315/85024(DRSS) and 316/85024(DRSS).

e. On September 11, 1985 the licensee reported that wide-range reactor coolant system pressure transmitters (which had been replaced in Unit 1 during the current outage) were being relied upon for their inputs to the low temperature overpressure protection system despite the fact they had not yet been declared "operable" after installation. The subject instruments are to open the power operated relief valves on a pressure transient, and had been relied on for this protection since September 5, when reactor coolant vents were closed. The licensee completed the necessary reviews to declare the system "operable" immediately upon identification of the problem. The system had passed a surveillance test, so the deficiency was administrative, not physical. The inspector verified the associated Technical Specification Action Statement time limit (7 days) was not exceeded. The subject instruments were among many which were replaced due to electrical equipment environmental qualification questions. Numerous other instruments in the main control room were tagged on September 10, 1985 (as were the subject instruments). This was well after the work had been started. No other examples of reliance on instrumentation of indeterminate status were identified.

f. On September 20, 1985 the licensee reported discovery of steel plates of questionable seismic qualification being used to support safety-related electrical components in both Unit 1 and Unit 2 containments. The plates were used as concrete forms in original construction of the steam generator and pressurizer enclosures. As such, there appears to have been no adequate analysis performed relating to the seismic capabilities of the plates. The licensee has decided to anchor the plates now in such a way the seismic capability will be adequately assured rather than attempting to determine the exact nature of the existing anchorage and analyzing that for adequacy. These repairs are extending the duration of the current Unit 1 outage and may hereafter affect the Unit 2 outage schedule as well.

   On September 26, 1985, the inspector met with members of the plant staff and by telephone with members of the corporate staff. The inspector was previously informed that a sample of the base plate was removed to verify material composition. Because the base material may not have been known the inspector asked if the correct weld procedure/material and appropriate non-destructive testing was performed when the safety-related electrical component supports were previously attached to the base plate. The licensee acknowledged the inspector's concerns and identified a program that should verify if the supports were adequately attached.

No violations or deviations were identified.

4. 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.

a. **12 THP 4030 STP.229 "Control Room Emergency Ventilation System Filter Efficiency Charcoal and HEPA Filter Leak Test" and **1 THP 6040 PER.094 "Unit 1 Control Room Ventilation Balancing." These were the activities conducted August 16 and 29 respectively, during which the problem with the Unit 2 control room emergency ventilation system (discussed below) was created and later found. The inspector's review focused on causative factors relating to the procedures and to corrective action approaches relating to these factors.

On August 29, 1985 the inspector was notified that in-progress testing of the Unit 1 control room emergency ventilation system had determined both the Unit 1 and Unit 2 emergency ventilation systems were incapable of performing as designed. Upon investigation the Unit 2 fresh air intake damper was found fully closed, such that neither system could maintain adequate positive pressure.

The licensee's investigation indicated an error was made in adjustment of the Unit 2 fresh air intake damper following testing on that unit on August 16, 1985. The subject damper is a two-position design, intended to be full-open in the pressurization mode and throttled to a pre-determined makeup setting in the cleanup mode. Following testing on August 16, the actuator arm on the fresh air intake damper was erroneously set to the makeup setting for pressurization, and full-closed for cleanup. The error remained undiscovered until August 29 in part because no functional check followed the final actuator arm connection adjustments.

Unit 1 remained in Mode 5 throughout the time period August 16-29, 1985. Unit 2, however, entered Mode 4 at 0023 hours on August 19, 1985 and proceeded to Mode 1 by 1401 hours on August 21, 1985. Power operation at up to about 30 percent full power then occurred until August 24, when the unit was shutdown due to primary-to-secondary leakage problems. Mode 5 was reached on August 25, at 0708 hours, and continued through the remainder of this inspection period. Pursuant to Technical Specification 3.7.5.1 (both units) the control room emergency ventilation system is required OPERABLE in MODEs 1, 2, 3 and 4. Because of system design, sufficient interaction exists between the two control rooms that the ability to maintain the specified positive pressure (per Technical

Specification 4.7.5.1.e.3) in one control room depends on correct conditions in the ventilation systems for both control rooms. In the case described above, though neither system was OPERABLE, requirements to have an OPERABLE system applied to Unit 2 only. Further, since the problem in system alignment was unrecognized, separate requirements of Technical Specifications involving not entering an operational Mode unless applicable system conditions are met (Technical Specification 3.0.4) and requiring action to place the unit in a Mode where the Specification does not apply (Technical Specification 3.0.3) were both violated.

The licensee is performing an evaluation of safety significance for the Licensee Event Report being prepared on this matter. NRC considers the described circumstances to be a Violation of Technical Specifications 3.0.3 and 3.0.4 for Unit 2. (Violation 316/85029-01).

b. **2 THP 4030 STP.146 "Containment Pressure Protection Set I Surveillance (Monthly)."

c. **12 THP 4030 STP.204 "Personnel Air Lock Leakage and Interlock Surveillance Test" and **12 THP 4030 STP.227 "Multiple Entry Personnel Air-Lock Leakage Surveillance." These procedures were reviewed pursuant to a review of Unit 2 Control Room Logs, during which the inspector identified an apparent failure to comply with the requirements of 10 CFR 50, Appendix J. The problem involved the means used to verify proper restoration (by test) of containment airlock integrity, following a period for which such integrity was neither required nor maintained.

According to the logs, Unit 2 was in Mode 5 from July 16 through 30, 1985. During this time (July 18 through 28) the licensee defeated the upper containment airlock interlocks to permit opening of the airlock (e.g. both airlock doors open at the same time) and improve containment accessibility for a number of ongoing activities. On July 27, the licensee resumed testing of the door seals on each airlock door via Procedure STP.227. This testing, which is required for each entry (or each three days when there are numerous entries) is only required when containment integrity is required. The seal testing was initially performed to demonstrate restoration of the airlock itself prior to returning the plant to Mode 4, where containment (and therefore, airlock) integrity is required.

When the airlock interlock was restored on July 28, the licensee considered containment integrity (at least insofar as affected by the airlock) to be re-established. Procedure STP.204 was not performed.

Title 10, Code of Federal Regulation, Part 50 (10 CFR 50) Appendix J, concerning periodic retest scheduling, requires at III.D.2(b)(ii) that "airlocks opened during periods when containment integrity is not required...shall be tested at the end of such periods at not less that P(a)." Door seal testing may be substituted for a test of the entire airlock only as specified in III.D.2(b)(iii), e.g., to demonstrate continuing integrity "...during periods when containment integrity is (emphasis added) required." Thus, use of the door seal test in lieu of a test of the entire airlock for purposes of re-establishing integrity at the end of a period when the locks were open and integrity was not required, is contrary to the referenced 10 CFR 50 Appendix J, and is considered a violation. (Violation 316/85029-02).

The violation reflects what had been standard licensee practice. Immediately upon identification of the licensee's apparent misunderstanding of these requirements, the inspector met with licensee representatives to assure the violation was not repeated in restoring Unit 1 to service. The licensee had intended to rely on a test of the door seals, but agreed to change the applicable procedures, thus preventing a repeat violation.

d. **1 OHP 4030.STP.034 "Local Valve Position Verification." This procedure was reviewed in conjunction with Condition Report 1-09-85-1824, which identified interaction among the Target Rock pressurizer and reactor vessel head vent valves during performance of the test, such that a control signal was given to one valve to open and two valves opened in one case and three valves in another. The inspector discussed this matter with selected licensee management as a known phenomenon involving valves of this manufacture if opened with a significant differential pressure across the valve. Some licensee personnel were aware of the phenomenon, and in fact the procedure STP.034 states the testing should be performed with the RCS pressure below 80 psig. This was discussed at the Management Interview.

e. **12 THP 4030 STP.228 "Engineered Safety Features Ventilation Performance Test." This matter was reviewed in conjunction with identification to the inspector by licensee management that the ventilation systems as designed are not capable of maintaining a uniformity of airflow within 20%, as specified by Technical Specification 4.7.6.1.d.2. This was referred to the Office of Nuclear Reactor Regulation via the Licensing Project Manager, who consulted with the technical staff. Their conclusion was that the intent of the Technical Specification would be met by introducing a calculational "penalty" into the determination of filter efficiency based on the degree of departure from the plus/minus 20% criteria. The licensee had done this with satisfactory results. Thus, a technically adequate test has been performed, but the "letter" of the Technical Specifications (involving ANSI N510-1975 criteria) is inconsistent with the system design. The licensee needs to address this incompatibility to permit a condition of compliance to the "letter" of Specifications. Action to resolve this matter is considered an Open Item. (Open Item 315/85029-01; 316/85029-03)

Two violations and no deviations were identified in this area.

5. Maintenance

Station maintenance activities of safety-related systems and components listed below were observed and/or reviewed to ascertain that they were conducted in accordance with approved procedures, regulatory guides and industry codes or standards and in conformance with Technical Specifications.

The following items were considered during this review: the limiting conditions for operation were met while components or systems were removed from service; approvals were obtained prior to initiating the work; and activities were accomplished using approved procedures.

The following maintenance activities were observed:

Electrical equipment painting, Unit 1 Auxiliary Building 633 foot level

**12 MHP 5021.019.001	Maintenance Repair Procedure for Essential Service Water Pump.
**12 MHP 5021.017.001 Rev 1	Maintenance Repair Procedure for Residual Heat Removal Pump.

While observing maintenance work related to the two procedures stated above, the inspector noted that the cleanliness inspection hold point sign-offs were being omitted. When questioned on this matter, licensee personnel pointed out that per Procedure PMI-2220, a new stamp on the job order itself was replacing the sign-off in the actual procedure. The inspector questioned the validity of removing the hold points from the procedure where they flag areas to be inspected before system closure, as opposed to having a single sign-off (though verified for Rating I, II systems) for cleanliness inspection on the job order. This practice relies on thorough knowledge of PMI-2220 as the basis for system inspection, and results in documentation which is non-specific with respect to when (which step in the procedure) the inspection was conducted. This was discussed at the Management Interview. The licensee expressed confidence in the level of training and qualification provided to those employees certified to perform the subject cleanliness inspections.

No violations or deviations were identified.

6. Confirmatory Action Letter

During this inspection, the inspector reviewed the licensee's activities and findings relating to a Confirmatory Action Letter (CAL) issued on August 30, 1985 to address licensee actions in response to several findings of an IE Headquarters Team Inspection conducted August 19-28. The CAL addressed three specific items relating to surveillance activities, which were to be completed prior to placing the plant in a Mode in which specific Technical Specification surveillances were applicable. On September 17, 1985, the inspector met with members of the licensee's Corporate and Plant staffs for the purpose of a briefing and summary. The licensee's representatives provided an overview of the program developed to implement CAL provisions, and then summarized the activities and findings of each involved Department for each of the below line items. The inspector concluded the scope of the licensee's reviews exceeded that mandated by the CAL. Findings may be summarized as follows:

a. (Open) Confirmatory Action Letter (315/85022-03; 316/85022-03): Conduct a review by both corporate Quality Assurance and Plant organizations of all surveillances which are contained in tabular form in the Technical Specifications to ensure that the surveillance scheduling meets the Technical Specification requirements.

   This item focused on timeliness of testing as to frequency or other scheduling requirements. The licensee found some examples where test scheduling had potential omissions due to considerations beyond the scope of the CAL, but no additional cases of scheduling lapses within the area directly covered by the CAL were found. The findings appearing to require some licensee action to correct or clarify the situation have been documented on Condition Reports. This will also assure a review for reportability and safety significance.

b. (Open) Confirmatory Action Letter (315/85022-04; 316/85022-04): Conduct a review by all departments of the surveillances which are contained in tabular form in the Technical Specifications to determine, for tests which are not the sole responsibility of a single department, that no omissions of test requirements exist and to determine which documents show how that responsibility is established.

   This item focused on completeness of testing, particularly where more than one Department might be involved in accomplishing the various parts of the overall testing of a given system to show satisfactory system performance. The licensee did not find any examples of testing requirements being overlooked and therefore not performed. Some examples of aspects of overall testing being accomplished "unintentionally", rather than by design, were identified. Corrective actions will be accomplished for those items which fell in this category, where appropriate, to assure the intended Department is performing and documenting the activity, and to clarify inter-departmental interfaces and documentation/ recordkeeping responsibilities.

c. (Open) Confirmatory Action Letter (315/85022-05; 316/85022-05): Conduct a review of Technical specification surveillances which involve calibration and time response testing of process sensors, and take actions to ensure that Technical Specification surveillance requirements are satisfied.

   This item addresses potential deficiencies in the licensee's interpretation as to the meaning of process "sensors", and the possible exclusion of certain devices from the calibration and time response testing programs on the basis of the interpretation. Discrepancies or questionable items are being addressed considering the individual technical and design considerations of the components in question. Few remain to be resolved. The major findings in this area involved calibration activities for the reactor coolant system hot and cold leg thermocouples. These were just replaced in Unit 1, during the current outage, with new factory calibrated sensors. A means for performing "in situ" calibration of the Unit 2 sensors is being developed.

Pending completion of the few identified items already known to the licensee as requiring resolution prior to MODE change, the licensee's actions in performing to the stipulations of the Confirmatory Action Letter were considered satisfactory.

No violations or deviations were identified.

7. Regional Request

The inspector was asked to determine whether the licensee was using controlled drawings that depict correctly the actual location of the manual trip circuit, and to confirm that the manual trip circuits are located downstream of the output transistors in the undervoltage (UV) output circuit.

a. Background

Information Notice No. 85-18 highlighted the effects of short-circuit failures of the output transistors in the UV output circuit of the Westinghouse Solid State Protective System (SSPS). A short-circuit failure of the type described in the Notice would prevent the automatic tripping of the associated reactor trip breaker (RTB) on a valid reactor trip demand.

During the review of this matter, another potential deficiency involving the SSPS was discovered. Namely, the use of erroneous controlled schematic diagrams of the SSPS at an operating facility. Except for the drawings being used by the I&C technicians, the controlled schematic diagrams of the SSPS being used at that facility erroneously depicted the manual trip circuit for the RTBs as being upstream of the output transistors. If such were the case, and if output transistors were shorted as described in Information Notice 85-18, then the manual trip action associated with the UV portion of the trip circuit would also be ineffective. However, manual trip action would be provided by separate contacts on the manual trip switch that are wired directly to the shunt trip coils of the RTBs.

Westinghouse had informed the NRC that all domestic plants with SSPS were designed with the manual trip downstream of the output breakers.

b. Inspection

Through discussion with the licensee and reviews of prints OP-1 and 2-98369-0, "Solid State Reactor Protection and Safeguard System - Train A" and OP-1 and 2-98389-0, "Solid State Reactor Protective and Safeguard System - Train B" the inspector verified that the manual trip circuits are located downstream of the output transistors.

No violations or deviations were identified.

8. <u>Reportable Events</u>

Through direct observation, discussions with licensee personnel, and review of records, the following Licensee Event Reports were reviewed to determine reportability requirements were met, and corrective and preventive actions were accomplished in accordance with Technical Specifications.

The following LERs are considered closed:

<u>Unit 1</u>

RO 315/84004-0 — The AFW pump turbine failed a surveillance test due to internal steam erosion and consequent pressure loss on steam needed to close the throttle trip valve. A leak-off line was capped to retain adequate operating pressure as an interim measure. Repairs to the eroded bushing and bonnet have been completed and a functional test will be performed prior to return to service during unit startup from the current outage.

RO 315/85016-0 — Strict control of containment integrity was not maintained when, following a hydrostatic test of the RHR system, drain valves were opened concurrently both inside and outside the containment with the unit still in Mode 4. The applicable Technical Specification Action Statement was not exceeded, in that Mode 5 was (coincidentally) achieved only 45 minutes later. The test procedure was revised to include appropriate guidance and precautions.

<u>Unit 2</u>

RO 316/83100-03L — The gauge protector on the east motor-driven auxiliary feedwater pump suction pressure trip switch became mechanically bound and rendered the pump inoperable. The applicable Action Statement requirements were met, the gauge protector replaced, and the switch calibrated and verified to operate correctly. The problem has not recurred since.

RO 316/83103-03L	The CVCS letdown isolation valve QCR-301 failed a stroke timing test due to boric acid solidification in the stuffing box from a small leak. The packing was cleaned, adjusted and the valve stroked satisfactorily.
RO 316/83115-03L	Pressurizer pressure fell below 2205 psig just prior to a reactor trip from about 30% power due to over-feeding the steam generators. Poor control room communications contributed, and were addressed in operator requalification training. Limited pressurizer heater capacity due to undersized heater breakers (which have since been replaced) may also have contributed.
RO 316/85004-0	One reactor coolant system cold-leg temperature RTD was discovered to be non-qualified environmentally pursuant to 10 CFR 50.49, because of a lack of qualification information on the RTD connection used in the installation about two months earlier. The plant was operating at the time the discrepancy was identified, but tripped off line the following day due to unrelated causes. The questionable RTD was replaced with a qualified device before plant restart. A number of other non-qualified devices remain in service, but these have been evaluated and are covered under NRC-granted temporary exemptions to 10 CFR 50.49, as provided for in that regulation. These will all require replacement before plant operation beyond November 30, 1985 unless an additional extension is granted by the Commission. Operation with the non-qualified RTD not evaluated and approved by NRC was in violation of 10 CFR 50.49. Since this matter was identified, reported, and corrected by the licensee and had minimal safety significance, no Notice of Violation is being issued.

One violation (for which no Notice of Violation is being issued - see above) and no deviations were identified in this area.

9. 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. An open item disclosed during the inspection is discussed in Paragraph 4.e.

10. Management Interview

The inspector met with licensee representatives (denoted in Paragraph 1 above) following completion of the inspection on October 1, 1985. The inspector summarized the scope and findings of the inspection as described in these Details. The following were specifically addressed:

a. The inspector stated the apparent Violations identified during the inspection for which a Notice of Violation would be issued (Paragraphs 4.a and 4.c).

b. The potential for problems in performing and documenting appropriate post-maintenance cleanliness inspections, due to transition conditions while applicable procedures are revised, was discussed (Paragraph 5). Licensee representatives remained confident their training and procedure use practices will minimize the potential for error.

c. The inspector expressed satisfaction with the activities conducted by the licensee in implementing a Confirmatory Action Letter concerning review of surveillance activities, indicating the review process appeared to satisfy (or exceed) the scope and depth specified. Corrective actions and/or resolution of questions remain in a few cases (Paragraph 6) and may be reviewed further at a later date.

d. The inspector indicated the licensee would be expected to take action to resolve an identified discrepancy in "testability" of ESF ventilation systems (Paragraph 4.e).

e. The degree of control of pressure conditions for testing the reactor head and pressurizer vent systems was discussed, in light of the known sensitivity of these valves to differential pressure. The licensee is continuing to investigate the cause of the unexpected valve behavior during the September 8, 1985 test.

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 documents/processes which might be proprietary, and none were so designated.