U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Reports No. 50-315/88027(DRP); 50-316/88031(DRP)

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

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

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

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

Inspection Conducted: November 17 through December 27, 1988

Inspectors: B. L. Jorgensen

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Approved By: B. L. Burgess, Chief
Reactor Projects Section 2A

1/11/89
Date

Inspection Summary

Inspection on November 17 through December 27, 1988 (Reports No. 50-315/88027(DRP); 50-316/88031(DRP))

Areas Inspected: Routine unannounced inspection by the resident inspectors of: actions on previously identified items; plant operations; reactor trips; radiological controls; maintenance; surveillance; fire protection; emergency preparedness; security; outage activities; safety assessment and quality verification; reportable events; and NRC Information Notices. Routine, announced inspection by an NRC consultant of: outage recovery, testing, modifications, and plant startup preparation activities for Unit 2. The consultant made a series of four inspection visits to the site from September 22 through December 13, 1988.

Results: No violations or deviations were identified in any of the fifteen areas inspected.

The inspection disclosed weaknesses in the licensee's documentation and traceability for resolution of problems or unusual conditions noted during complex testing (Paragraphs 12.b and 12.g). There also appears to be a need for closer management attention to or involvement in complex, infrequent activities (especially those involving multiple groups) as evidenced by problems occurring in these activities (Paragraphs 12.a, 12.d, 12.g and 14.c).

The inspection noted strengths in the licensee's degree of sensitivity and responsiveness to NRC concerns (Paragraphs 3.c and 14.c), and his focus on identifying adverse trends (Paragraph 14.a) while emphasizing technical/safety content of issues (Paragraph 14.b). The Security group showed an aggressive, conservative viewpoint and responded effectively to events and changing requirements (Paragraph 10).

One new Open Item was identified (and is discussed in Paragraph 3) in the inspection area of operational safety verification.

DETAILS

1. Persons Contacted

   a. Resident Inspectors

      *W. Smith, Jr., Plant Manager
      A. Blind, Assistant Plant Manager, Administration
      *J. Rutkowski, Assistant Plant Manager, Production
      *L. Gibson, Assistant Plant Manager, Technical Support
      *B. Svensson, Licensing Activity Coordinator
      *K. Baker, Operations Superintendent
      *J. Sampson, Safety and Assessment Superintendent
      E. Morse, QC/NDE General Supervisor
      *T. Beilman, I&C/Planning Superintendent
      J. Droste, Maintenance Superintendent
      *T. Postlewait, Technical Superintendent, Engineering
      *L. Matthias, Administrative Superintendent
      *J. Wojcik, Technical Superintendent, Physical Sciences
      M. Horvath, Quality Assurance Supervisor
      D. Loope, Radiation Protection Supervisor

   b. NRC Consultant Inspector

      *R. Vonk, Production Control Supervisor
      *R. Rickman, ISI Supervisor
      E. Abshagen, I&C Supervisor (RFC)
      J. Bobay, Outage Planning Supervisor
      M. Gallagher, Operations Engineer
      W. Kirchoff, Hydro Engineer
      S. Macey, Performance Engineer
      M. Mitch, Performance Engineer
      W. Pauls, Design Change Coordinator
      S. Richardson, Operations Production Supervisor
      *H. Runser, Operations Production Supervisor
      J. Schwerha, Operations Engineer
      M. Stark, Performance Supervisor
      R. Tella, Maintenance Engineer

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

   *Denotes some of the personnel attending Management Interviews on December 13 and/or 28, 1988.

2. Actions on Previously Identified Items (92701)

   a. (Closed) Unresolved Item (315/85029-01; 316/85029-03): Ventilation systems are not testable per ANSI N510-1975 as specified in Technical Specification 4.7.6.1.d.2. The licensee has taken the actions available to him to resolve this item; the matter is now in the hands of NRC for a license amendment. The stipulation of ANSI N510-1975 (and the referenced Technical Specification) to control air flow uniformly within 20-percent is unachievable, so the licensee compensates by using an NRC-approved penalty factor in his test. This meets the "intent" of the specifications (ref. Inspection Report No. 50-315/85029). To re-establish a condition of "literal" compliance, a Technical Specification amendment has been applied for (ref. Inspection Report No. 50-315/88002). This is not a high priority licensing action, but it has been entered into and is being tracked by NRC's licensing activity tracking system.

b. (Closed) Unresolved Item (316/85035-09): Model DB-50 reactor trip breakers were subjected to onsite repairs by Westinghouse (the manufacturer) without benefit of a Job Order or of plant or manufacturer procedures. This appeared to be contrary to plant administrative requirements, which specified such controls for repair of plant equipment. The administrative controls were determined not to apply in this case because the subject breakers were not "plant equipment" at the time of repair. They had been received onsite but had not been accepted for service. It was service acceptance testing, in fact, which identified the need for repair prior to use. While the details of this repair were not controlled or documented via Job Order or procedure, its acceptability was subsequently established and documented via successful completion of the acceptance testing. This sequence of actions left less-than-optimum documentation concerning potentially significant activities associated with these safety-related components, but plant administrative requirements technically did not apply and were therefore not violated.

c. (Closed) Open Item (316/85035-10): Model DB-50 reactor trip breakers were not lubricated before use onsite because they were considered (without documentary evidence) to have been lubricated during an offsite refurbishment by Westinghouse (the manufacturer) a couple of months earlier. Documentary evidence of the lubrication at the factory was produced, but proved somewhat uncertain. Subsequent periodic lubrication required by a PM has been performed onsite and makes the question moot as applied to breakers currently in service.

d. (Closed) Open Item (316/85036-01): Procedure changes made for one Unit need to be reviewed and implemented for the other Unit, if applicable. As indicated in Inspection Report No. 50-316/87007, an opposite-Unit review step was implemented for Operations Department procedures, and mechanisms were being considered for implementing a similar process within the I&C group. These were the groups which had significant numbers of Unit-specific procedures. The licensee currently considers opposite-Unit review desirable but not mandatory, and not of sufficient importance to make mandatory by inclusion of a procedural review requirement. The Operations Department no longer mandates such a step, and I&C never adopted one. The matter is not subject to an NRC requirement, nor have differences which have developed between procedures for the two Units caused significant difficulties.

No violations, deviations, unresolved or open items were identified.

3. Operational Safety Verification (71707, 71710, 42700)

Routine facility operating activities were observed as conducted in the plant and from the main control rooms. Plant startup, steady power operation, plant shutdown, and system(s) lineup and operation were observed as applicable.

The performance of licensed Reactor Operators and Senior Reactor Operators, of Shift Technical Advisors, and of auxiliary equipment operators was observed and evaluated including procedure use and adherence, records and logs, communications, shift/duty turnover, and the degree of professionalism of control room activities.

Evaluation, corrective action, and response for off normal conditions or events, if any, were examined. This included compliance to any reporting requirements.

Observations of the control room monitors, indicators, and recorders were made to verify the operability of emergency systems, radiation monitoring systems and nuclear reactor protection systems, as applicable. Reviews of surveillance, equipment condition, and tagout logs were conducted. Proper return to service of selected components was verified.

a. The inspector performed a walkdown of selected portions of the Unit 1 North and South safety injection systems. Licensee Drawing OP-1-5142, and Valve Lineup Sheet No. 1 from Procedure **1-OHP 4021.008.002, "Placing Safety Injection System in Standby Readiness" were used in this walkdown.

   All valves and controls checked (about 50 items) were found to be positioned as specified. Further, for each vent, drain or sample point identified as "capped" - the cap was present. Five such points, however, had caps even though not specified on the lineup sheet. Also, a couple of minor inconsistencies were noted in nomenclature, comparing valve tags and lineup sheet descriptions. These were referred to the Operations Procedure Group for followup.

b. The inspector performed a walkdown of the containment spray system utilizing Data/Signoff Sheet 5.1 "CTS Valve Lineup for Standby Readiness," from licensee Procedure **1-OHP 4021.009.001 "Placing Containment Spray System in Standby Readiness." Licensee piping Diagram OP-1-5144 was also used in this walkdown.

   All valves and controls checked (about 80 items) were found to be in the correct position. Further, each component designated to be locked, sealed or capped was found configured as specified. More than twenty vents, drains or test points were noted, however, which had caps, plugs, or blank flanges not stipulated on the lineup sheet. Similarly, over twenty valves were either locked or sealed in their specified position, but the lineup sheet was silent with respect to such locks or seals. A couple of valves were missing identification tags, one had a severely corroded tag, and two tags had slightly different nomenclature from that on the lineup sheet. These observations were referred to the Operations Department for appropriate followup.

The local position indicator on one motor-operated valve (MOV 1-IMO-212) supplying the East CTS pump discharge to its eductor, showed the valve at about 55-percent open versus fully open. A further check found the valve was fully open, so a Job Order was initiated on the errant local indicator. This is not expected to result in the repair of the indicator. These devices have been relatively difficult to keep in good working order, and spare parts unavailability is a problem. Therefore, a usage survey was conducted in the Operations Department in about April 1988. A list of eight MOV's was generated, (four per Unit) for which operators said they relied on the local position indicators to determine valve position. Blanket authorization has been granted from Operations to Maintenance to "disable" local position indicators on all other MOV's. They are being painted over as they fail. This caused the inspector some concern relating to capability to control and verify proper MOV positions for valves whose safety action is to go to an intermediate or "throttled" position. This concern is discussed further in Paragraph 6, "Maintenance."

An operational concern was also identified. In cases involving a need to manually operate MOVs, the limit switch lights would not be functioning to indicate position and the local dial indicator might have to be relied upon. An inspector screening of selected emergency operating procedures, addressing electrical blackouts and fires, found no examples of procedural instructions (or strong implications) to set valve positions manually using local position indicators. Many instructions involve manually operating MOV's, but the typical instruction focused attention on an affected parameter (e.g., level, flow, pump amps) to set valve position correctly.

The procedures reviewed included:

(i) 01-OHP 4023.001.001, "Emergency Remote Shutdown"

Note: Various attachments (including LS-5 and LS-7 specify MOV's to be verified open or closed, without further instruction concerning how to perform this verification. Some MOV designs used at the plant appear to have no external indication of position except the subject dial indicators.

- Attachment R-4, on Pages 9 through 12, specifies manual opening of Essential Service Water MOV's to Emergency Diesels; these valves would open only to a preset throttled position with their motor operators. It is unclear whether full opening is proper in the situation addressed in this Attachment.

(ii) 01-OHP 4023.ECA-0.0, "Loss of All AC Power"

(iii) 01-OHP 4023.ECA-0.1, "Loss of All AC Power - Recovery Without SI Required"

(iv) 01-OHP 4023.ECA-0.2, "Loss of All AC Power - Recovery With SI Required"

Discussions with Operations Department personnel indicated that, prior to May 1988, the Maintenance Department was painting over failed local dial indicators only if a valve-specific review by Operations determined the indicator was not needed. The criteria for the generic review, which eliminated all but eight valves as needing local indication, appear to have been loosely defined, and were not well documented. It was thus unclear whether detailed consideration was given to procedural references or implications, utilization in testing, diverse indication needs, etc. It was also unclear to the inspector whether abandonment of the broken gauges "in-place" could result eventually in the broken part(s) binding or interfering with proper motor and/or valve operation. The inspector discussed this matter with plant management during the inspection and at the Management Interview. Pending further inspection, the lack of clarity regarding procedural guidance is considered an Open Item (315/88027-01).

c. On December 16, 1988, the licensee received verbal notification from Westinghouse concerning a planned 10 CFR Part 21 report with applicability to D.C. Cook. Unit 1 was in power operation at the time, while Unit 2 was defueled and in an extended outage.

Westinghouse reported that three Type DB-50 circuit breakers, from a suspect lot of 30, had apparently been shipped to D.C. Cook. The breakers were considered suspect based on findings at another nuclear plant (Turkey Point) that spot welds holding a secondary contact strip support bracket were deficient and, in one case, had failed in service. Serial numbers were provided for the three breakers believed to be at D.C. Cook. These breakers are used as reactor trip and rod drive motor-generator (M-G) set output breakers.

The licensee verified by document review on December 16 and reverified by in situ inspection on December 17 that no suspect breakers were in service in Unit 1, the operating Unit. A safety evaluation was performed in parallel, based on the reported failure mode being to the breaker OPEN position. Corrective action documentation (Problem Report 88-929) was initiated. The inspector attended the

December 19 Problem Assessment Group (PAG) meeting which evaluated and assigned the referenced Problem Report for investigation and action. Two of the suspect breakers were located on Saturday, December 17; one installed as the "A" reactor trip breaker in Unit 2, one as a spare motor-generator set breaker being held in stock. The third breaker was believed to have been returned to Westinghouse. The licensee committed not to utilize any suspect breakers until establishing its acceptability. This was verified at the Management Interview.

One open item, and no violations deviations or unresolved items were identified.

4. Reactor Trips or ESF Actuations (93702)

a. D.C. Cook Unit 1 tripped from 90-percent power at 11:03 p.m. on November 23, 1988. The first indication of cause was reactor coolant low flow. All four reactor coolant pumps also tripped despite no indication of bus underfrequency or faulting on any of the pump buses.

The plant was stabilized without difficulty on natural circulation. Because of the lack of forced circulation, an Emergency Plan "Unusual Event" was declared at 11:20 p.m. and applicable notifications were made (see Paragraph 9).

Electrical system inspections found no abnormalities on any of the reactor coolant pump buses or switchgear. The first pump restart (No. 13) occurred at 1:35 a.m. on November 24, reestablishing forced circulation and normal pressurizer spray. A second pump (No. 11) was restarted shortly thereafter, leading to termination of the "Unusual Event" at 1:54 a.m.

The inspector arrived onsite around 1:00 a.m. November 24 and observed the pump restarts and "Unusual Event" termination. Preventive and corrective maintenance, testing, and initiation of root cause evaluation, were followed.

A primary coolant pressure boundary inspection showed no significant leaks - "unidentified" leakrate had been less than 0.2 gpm. Oil was added to the reactor coolant pump reservoirs as necessary.

Routine and specialized testing by I&C technicians identified no failed components, but two circuit cards in Train B (which actuated first) were replaced because they could have caused the observed sequence of events. A few days later, the Train A cards were also replaced as a precaution. All of the new cards were tested satisfactorily.

Because no specific root failure could be identified, the licensee's Plant Nuclear Safety Review Committee (PNSRC) was convened at 8:00 p.m. on November 24 to review the investigative, corrective and preventive

actions. No unreviewed safety questions were identified, so PNSRC recommended (and the Plant Manager authorized) restart. The reactor was critical at 2:22 a.m. on November 25, and subsequently returned to normal power operation.

b. An unexpected ESF actuation, in the form of a Train A Phase B containment isolation and spray actuation signal, occurred in Unit 2 at 9:12 a.m. on December 13, 1988. The Unit was in MODE 6 with no fuel.

A surveillance test was in progress at a point involving the response timing for the steam generator stop valve "dump valves." When the test switches were actuated per procedure, the "dump valves" actuated (and were timed satisfactorily) as planned, but the Phase B actuation also occurred. The subject test is performed infrequently, during outages, and the test switches used on this occasion had not been used for this purpose before. A re-examination of the situation showed that the logic card through which the test switches actuated the slave relays for the "dump valves" also output to a "driver card" to Phase B and containment spray actuation relays. This was overlooked in the technical and safety reviews of the procedure, and in consultations with Westinghouse, which the licensee considered a proponent of the new method. Train B testing was placed on hold pending procedural modifications and renewed consultations with Westinghouse.

The unexpected signal caused some valve actuations but, due to plant conditions, no practical problems. Affected valves were restored to pre-actuation positions as needed.

No violations, deviations, unresolved or open items were identified.

5. <u>Radiological Controls (71707)</u>

During routine tours of radiologically controlled plant facilities or areas, the inspector observed occupational radiation safety practices by the radiation protection staff and other workers.

Effluent releases were routinely checked, including examination of on-line recorder traces and proper operation of automatic monitoring equipment.

Independent surveys were performed in various radiologically controlled areas.

a. Significant increases in the amount of plant and plant-contracted work activity occurred in Unit 2 areas during this inspection period. A notable increase in the frequency of personnel contamination incidents also developed, sometimes involving several events per day. The average number over calendar year 1988 was less than one per day. This trend was recognized promptly because each event is

specifically discussed at a daily meeting involving senior management. The effect of management intervention in reversing this trend will be followed in ongoing inspections. Early results appeared favorable.

b. The plant exercises control on the location, nature, amount, and duration of temporary storage of radiologically contaminated materials under Procedure 12 PMP 6010.RPP.301, "Control of Equipment and Material in a Restricted Area." A laydown area request form (Form RP-301) requiring the approval of both the working group supervisor requesting the area, and a radiation protection supervisor, documents these and other controls. Controls of this type were not imposed for temporary storage areas created by the Unit 2 steam generator repair project (SGRP). A number of these areas were noted during this inspection in what are soon to become plant operating areas, including the Turbine building, a "clean" area. The inspector discussed plans for clearing out SGRP materials (responsibilities, schedules, etc.) with licensee representatives. The existing understanding is that the area turnback process will control the situation; the arrangement being that the plant will not accept turnback with any residual contaminated materials. In limited cases, at the discretion of the plant, useful items are being transferred to plant control. For example, ALARA considerations led to the plant accepting already-installed temporary shielding instead of having it removed by SGRP and plant shielding being put in its place. The effectiveness of the turnover arrangements as they relate to clearing out SGRP contaminated materials will be followed as part of the continuing inspection of Unit 2 startup preparations.

No violations, deviations, unresolved or open items were identified.

6. Maintenance (62703, 42700, 60705)

Maintenance activities in the plant were routinely inspected, including both corrective maintenance (repairs) and preventive maintenance. Mechanical, electrical, and instrument and control group maintenance activities were included as available.

The focus of the inspection was to assure the maintenance activities reviewed 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; activities were accomplished using approved procedures; and post maintenance testing was performed as applicable.

The following activities were inspected:

a. Job Order JO 020978: Emergency Diesel Generator main bearing removal, inspection, and installation per Procedure **12 MHP 5021.032.017 and RFC No. 12-2945.

b. Job Order JO 40220: Clean and paint the lower inside portion of 2AB diesel generator starting air receiver tank 2-QT-141-AB1 per Procedure **12MHP 5021.100.001.

c. Job Order JO 020974: Perform 18-month inspection of 2CD emergency diesel engine, per Procedure **12MHP 4030 STP.046.

The inspectors observed part of the 24-hour run per STP.046 and noted various small cylinder head and inspection cover oil leaks, a jacket water leak just above the No. 1 cylinder, and a loose pipe support on the oil crankcase blower line. After the diesel run, the inspectors reviewed pertinent records to see if personnel performing the run had also observed and documented these deficiencies.

The concurrently effective operating procedure (**2 OHP 4021.032.001) contains generalized instruction on its Attachment 1 to check fuel, lube and cooling lines for leaks and to write Job Orders as necessary, but operations personnel initiated no Job Orders to correct the deficiencies. Assigned maintenance personnel, however, made these same observations (except the loose pipe support) and the defects are documented in the controlling maintenance procedure as requiring correction. The loose pipe support was added to the corrective action list.

d. Job Order JO 017548: Receive, inspect and store new fuel assemblies in the Spent Fuel Pool (see also Paragraph 7, "Surveillance").

e. Job Order JO 016423: Observed alignment and torquing of new Reactor Coolant Pump seal assemblies per Section 7.14 of Procedure **12 MHP 5021.002.003, "Removal, Inspection and Replacement of the Reactor Coolant Pump Controlled Leakage Seals." The quality control group was verifying and then re-verifying correct torque settings on all the pump couplings to spool piece bolts on all four Reactor Coolant Pumps (RCPs).

At the time of the inspection, vibration probes, seal temperature instruments, and some oil collection tubing were all disconnected or disassembled on RCP No. 24. Subsequent further review of the procedure showed the vibration probes and temperature circuits were specifically addressed in Section 8.0 "Restoration." The oil collection tubing was not addressed, but was found reconnected on a subsequent inspection tour.

f. Job Order JO 028833: Install blank flange at East Essential Service Water Pump discharge to prepare for system hydrostatic testing (job performed by CIMCO); see also Paragraph 7, "Surveillance."

g. The inspector followed up a concern relating to the proper setting and maintenance (including periodic verification) of correct Motor-Operated Valve (MOV) positions, particularly for MOVs whose correct safety position is an intermediate one - e.g., neither full-open nor full-closed. This concern arose in pursuing whether safety-related MOV 1-IMO-212, indicating locally to be 55-percent open, was actually full-open as required - see Paragraph 3.b above. The inspector learned that local position indicators are not utilized either for original valve positioning or for periodic verification of correct positioning. Original positioning is governed by the Maintenance Department setting of limit or torque switches per approved Maintenance procedures (for full-open or full-closed valves) or by setting open limit switches to criteria (based on flow testing) from the engineering and testing group for "throttled" valves. Thereafter, valve lineups and periodic verifications are performed utilizing control room indicating lights operated off the limit switches. The licensee's experience has been that the limit switch assembly is much more reliable (less subject to breakage or maladjustment) than the local dial indicator. For throttled MOV's, limit switch "drift" is identifiable by a change in stroke time. This was shown, coincidentally, during this inspection when a post-maintenance stroke timing test identified that the "open" limit switch had been mispositioned (ref. Problem Report 88-873). The inspector concluded the licensee's practices in setting, maintaining and verifying proper MOV positions are adequate, so long as power is available.

h. **12 MPH 5021.082.012**: "Maintenance Inspection and Repair Procedure for Westinghouse Type DB-50 Air Circuit Breakers Installed as Control Rod Drive Motor Generator Output Circuit Breakers." This procedure was subjected to a brief specific review for attributes involving inspection of the secondary contacts, associated terminal strip, and support bracket(s) for each. The review was prompted by a December 16, 1988 verbal notification from Westinghouse that three DB-50 breakers potentially in service at D.C. Cook could have poor auxiliary contact terminal strip support bracket welds (see also Paragraph 3.c). The subject procedure contained a variety of general inspection and component functional check requirements relating to the operability of secondary contacts (i.e., checks for: loose bolts; bent, broken or discolored parts; functional working of switches/contacts) but nothing likely to identify any deficient spot welds in the application of concern (structural weld-integrity).

i. Job Order JO 029645: Troubleshoot and repair radiological monitoring instrument Channel VRA-2410. The channel was experiencing frequent undervoltage failures. Procedure **2 THP 6030 IMP.412, "Calibration of High Range Containment Monitor VRA-2410," was being used to guide the troubleshooting.

No violations, deviations, unresolved or open items were identified.

7. Surveillance (60705, 61726, 42700)

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.

The following activities were inspected:

a. **12 MHP 4050 FDF.005, "Handling of New Fuel Assemblies and Inserts for Inspection and Associated Work."

b. **12 SHP 4050 QC.001, "Receipt, Storage, and Inspection of New Fuel Assemblies."

c. **2 MHP 4030 STP.034, "18-Month Surveillance Test Procedure for Plant 2AB Battery Emergency Load Discharge Test and Battery Charger Test."

d. **2 THP 4030 STP.203, "Surveillance Test Procedure Type B and C Leak Rate Test." Test Steps 011 and 012 for Reactor Coolant Pump (RCP) No. 4 motor cooler lines were observed, as were Steps 089 and 090 for RCP oil coolers and thermal barriers.

e. **12 MHP 4030 STP.018, "Weekly Surveillance of Unit 1 Diesel Driven Fire Pump Battery."

f. **2 OHP 4030 STP.027CD, "CD Diesel Generator Operability Test (Train A)."

g. **2 OHP 4021 032.001, "Starting, Paralleling, Loading, and Shutting Down The Emergency Diesel Generators." Attachments to this operating procedure were being used as specified to document various test data required under STP.027CD immediately above. See also Paragraph 6.c.

h. **2 MHP 4030 STP.022, "18-Month Surveillance Discharge Test on 2CD Battery and Charger."

i. **2 OHP 5070 ISI.049, "Inservice Inspection Pneumatic Test Procedure Gas Sample Piping at CPN's."

j. **2 THP 6030 IMP.129, "Source Range Nuclear Instrument Calibration (N31 and N32)." This test was to satisfy two purposes, as reflected by two Job Orders requesting the calibration be performed. One purpose was to fulfill the routine 18-monthly periodic calibration requirement of Technical Specifications. The other purpose was to demonstrate post-modification operability of the affected channels following a design change which rerouted power supply and detector feedback cables. Operability is required prior to Unit 2 fuel reload.

No violations, deviations, unresolved or open items were identified.

8. Fire Protection (71707, 64704)

Fire protection program activities, including fire prevention and other activities associated with maintaining capability for early detection and suppression of postulated fires, were examined. Plant cleanliness, with a focus on control of combustibles and on maintaining continuous ready access to fire fighting equipment and materials, was included in the items evaluated.

The inspector reviewed licensee implementation of commitments to either maintain backup safe shutdown equipment "OPERABLE" or to implement appropriate compensatory measures. The review followed a voluntary special report to NRC Region III which described the implementation of backup compensatory measures (in the form of fire tours or fire watches) because safe shutdown equipment in Unit 2 was not OPERABLE (for Unit 1 safe shutdown) for more than 30 days.

The licensee's actions were in compliance with his commitment, and showed licensee personnel were knowledgeable concerning the duration of outages of alternate safe shutdown equipment. To enhance such status knowledge, an Appendix R Status Board was developed and placed in the Unit 2 control room. Operating Memo 88-122(I) dated December 7, 1988, assigned to the control room operators the responsibility to keep the Status Board current and accurate and to initiate compensatory measures whenever required.

No violations, deviations, unresolved or open items were identified.

9. Emergency Preparedness (82201, 82203)

The licensee declared an Emergency Plan "Unusual Event" as noted in Paragraph 4.a above, when Unit 1 tripped on loss of all four reactor coolant pumps on November 23, 1988. The "Unusual Event" declaration followed the trip by some 16 minutes. The classification of the event and subsequent notifications appeared correct. The event was declassified after restoration of forced circulation about three hours later.

No violations, deviations, unresolved or open items were identified.

10. Security (71707)

Routine facility security measures, including control of access for vehicles, packages and personnel, were observed. Performance of dedicated physical security equipment was verified during inspections in various plant areas. The activities of the professional security force in maintaining facility security protection were occasionally examined or reviewed, and interviews were occasionally conducted with security force members.

a. The inspector observed initial response to and implementation of compensatory measures for a loss of certain physical security program capabilities on December 19, 1988. A circuit breaker in the switchgear room of the normal site access control building blew

out at 4:37 p.m. that date, leading to a loss of power for some lighting and CCTV circuits and search equipment. The facility was immediately closed as a site access or egress point and the alternate (construction access) facility, which was unaffected, was used for all traffic. Guards were strategically located around the affected perimeter within minutes. Compensatory measures remained in effect until 6:22 p.m., when power and equipment were restored to normal. Security computer facilities were not affected.

b. The licensee implemented dedicated compensatory measures in early December 1988 (and maintained them continuously thereafter) upon reclassification of certain electrical equipment from a lower security classification to a higher one. These actions were the ultimate result of the licensee's extended efforts over about the last two years to address and resolve concerns raised by the NRC resident inspector. During this inspection, guards on the affected posts were interviewed and determined to be specifically knowledgeable about the applicable post orders.

c. On October 25, 1988, the NRC promulgated new regulations at 10 CFR 50.70 involving unannounced NRC inspector access to (Part 50) licensed facilities. By memorandum dated November 11, 1988, the licensee's physical security organization announced issuance of a revised Standing Order ASO-024 to implement the new requirements at the main plant access control facility. Security officer briefings and training were being developed. These and other licensee activities on this topic appeared appropriate to the need to implement changed requirements.

d. A security officer on tour in the plant on November 29, 1988, observed and established immediate compensatory measures for a developing breach in a physical security barrier of which the Security Section had not been notified. Workers were removing a cement block out of a wall to permit testing of the block and verification (or counter-verification) of its "rating" as a fire barrier. The wall also constituted a physical security barrier - a fact overlooked in review and authorization of the work. The security officer's alert intervention likely prevented an inadvertent violation of requirements in the Security Plan. Problem Report 88-853 was initiated to examine, control and document corrective action for the cause(s) of this apparent work control problem.

No violations, deviations, unresolved or open items were identified.

11. Preparations for Plant Startup (71711)

a. The following significant activities involving the Unit 2 steam generator repair project, a number of which were observed by the resident inspector, occurred during this inspection:

(1) primary and secondary insulation replacement
(2) secondary system hydrostatic testing (see Paragraph 12)
(3) primary system hydrostatic testing (see Paragraph 12)
(4) removal of repair project upper containment operating deck
(5) removal of concrete forms and internal falsework
(6) reinstallation of upper containment HVAC
(7) restoration of miscellaneous disconnected systems
(8) reinstallation of permanent ladders, walkways and grating
(9) final shim of reactor coolant pumps and lower SG lateral restrains
(10) upper containment cleanup and painting

The NRC consultant began an ongoing review of the licensee's plant startup planning and coordination to ascertain whether systems disturbed during the outage would be returned to an operable status prior to plant startup and whether plant testing, heatup, and startup, would be conducted in a controlled manner and in accordance with approved procedures.

b. Coordination of Unit 2 Return to Service

Replacement of the steam generators was managed by American Electric Power Service Corporation (AEPSC) corporate personnel through the establishment of a special Steam Generator Repair Project (SGRP) organization. Much like a new construction project, the reactor was defueled and the affected systems and equipment were "turned over" to the SGRP and largely removed from plant staff control and cognizance. As the SGRP work was completed, the systems and equipment were being progressively "turned back" to the plant staff for testing and restoration to service. These turnback activities were being controlled by plant Procedure 2-OHP-SP.068, "Unit 2 Return to Service from Steam Generator Repair" and project Procedures PP-14-01, "SGRP Plant Area Turnover Procedure" and PP-14-02, "SGRP Systems Turnover Procedure." The procedures collectively provided for identification of turnback packages, criteria for their acceptance by the plant, administration of incomplete construction items and deficiencies, turnback documentation, and prerequisite turnbacks for major plant testing and startup evolutions.

The implementation of these procedures for turnback and initial hydrostatic testing of the steam generators was reviewed by the NRC consultant, including review of turnback documents, and attendance at various coordination meetings. For the activities observed, the licensee appeared to be directing considerable attention and effort to the turnback process and the process appeared to be effective.

c. Restart Test Program

The NRC Office of Nuclear Reactor Regulation (NRR) had reviewed the licensee's plans for restart testing and startup activities. An NRR letter, J. F. Stang (NRR) to M. P. Alexich (AEP), "Restart Program for the SGRP" (TAC No. 68423), dated October 4, 1988, documented that the restart test program plans were acceptable and included a listing of about 100 plant procedures used, in part, for that conclusion.

On November 3, 1988, the Assistant Plant Manager, Technical Support, orally advised the NRC consultant that the listed procedures were not all part of the restart test program and may have been misconstrued by NRR. Copies of the procedures had been informally provided to NRR as general examples of the procedures to be used at the facility. The licensee had not intended that they each be considered a licensee commitment as a component of the restart program, in that some of them were not planned for performance prior to restart.

The licensee subsequently provided a review of these procedures (Memo, M. C. Gallagher to L. S. Gibson, December 5, 1988) denoting which procedures would and would not be performed prior to or as part of the plant startup. The NRC consultant's review of the memo determined that the procedures fall into the following categories:

(1) Procedures which will be used as part of the test program and startup.

(2) Operating procedures which are used only as-needed and may not be used during startup.

(3) Surveillance and test procedures which are on prescribed schedules, do not require performance prior to restart, and involve systems or equipment not affected by the outage.

(4) Special case or non safety-related procedures which are used only as-needed and are not planned for performance.

A sample of the procedures in Categories 3) and 4) were reviewed, the licensee's listing was cross-checked with the NRC listing, and current schedules were confirmed to be consistent with the licensee's conclusions. The licensee's position and plans appeared to be acceptable and were referred to NRC Region III for final disposition.

d. Control Rod Drive Shaft Storage Conditions, Cleaning and Inspection

Prior inspections by the resident and Region III inspectors found that the reactor cavity water in which the shafts were stored had significant surface contaminants and dirt from construction activities, raising concerns about the cleanliness and possible chemical contamination of the shafts. Chemical analysis of the water, plans for cleaning the shafts, and pre-installation inspection plans were reviewed. One area of concern remained at the end of the inspection period.

Instructions for remote video inspection of the shafts are included in draft refueling Procedure 2-OHP.SP.071, "Refueling," Step V.A.1. This step, to be performed by the licensee's refueling contractor, did not contain any guidance or criteria for the acceptability of the shafts. Discussions with the cognizant AEPSC and plant engineers indicated that the primary areas of concern are the presence of debris which could cause damage, the presence of pits or nicks, and the general shaft surface condition. The licensee representatives further advised that the contractor has extensive experience in such inspections and that the licensee planned on relying heavily on the contractor's judgement. The cognizant licensee production supervisor advised that the draft procedure would be reviewed and more detailed criteria considered for incorporation. Licensee disposition of the above will be reviewed during the continuing inspection.

No violations, deviations, unresolved or open items were identified.

12. Complex Surveillance Testing (61701)

Surveillance testing plans, procedures, and test data were reviewed and portions of major hydrostatic test procedures and complex surveillance tests were witnessed. The tests were reviewed to verify that the procedures were properly approved, met applicable technical, regulatory and administrative requirements, and were properly performed. A sample of procedures were reviewed in preparation for eventual test witnessing and data review:

- **12-THP-4030.STP.218, "Automatic Operation of Auxiliary Feedwater Pumps," Revision 11
- **2-OHP-4030.STP.008, "Emergency Core Cooling System Cold Shutdown Test," Revision 6
- **12-THP-4030.STP.228, "Engineered Safety Feature Exhaust Unit Surveillance Tests," Revision 6
- **2-THP-SP.124, "Auxiliary Feedwater Flow Retention Verification Procedure," Revision 0
- **12-THP-6040.PER.087, "Lower Containment Ventilation System Airflow Balancing," Revision 3
- **12-THP-4030.STP.208BI, "ECCS Flow Balance - Boron Injection," Revision 6
- **12-THP-4030.STP.208SI, "ECCS Flow Balance - Safety Injection," Revision 6
- **2-OHP-5070.ISI.019, "Inservice Inspection Hydrostatic Test Procedure RHR: East and West Trains and Normal Cooldown Path to Loop 2 and 3 Cold Legs," Revision 0

- **2-OHP-5070.ISI.007, "Inservice Inspection Hydrostatic Test Procedure ECCS: Charging and Injection Piping at the Cold Legs," Revision 0

- **2-OHP-5070.ISI.005, "Inservice Inspection Hydrostatic Test Procedure ECCS: Low Head Safety Injection at Hot Legs," Revision 1

- **2-OHP-5070.ISI.021, "Inservice Inspection Hydrostatic Test Procedure ECCS: North and South Safety Injection Pump Discharge Piping," Revision 1

- **2-OHP-5070.ISI.004, "Inservice Inspection Hydrostatic Test Procedure ECCS: Low Head Safety Injection at Cold Legs and Accumulator Fill/Discharge Piping," Revision 1

Selected surveillance tests were also reviewed and witnessed to verify that the procedures were technically adequate, that test prerequisites were completed, special test equipment was calibrated and properly installed, that the data was properly obtained and discrepancies identified and corrected, that system and equipment were properly restored to service, and that the test results were acceptable. Portions of the following tests were witnessed:

- **2-OHP.SP.069, "RCS Heatup and Cooldown for Shim Measurements and RCS Hydro Following SGRP," Revision 0

- **2-OHP-5070.ISI.002, "Inservice Inspection Hydrostatic Test Procedure, RCS: RX Vessel, RCP's, Steam Generators, & Associated Piping," Revision 0

- **2-OHP-5070.ISI.038, "Inservice Inspection Hydrostatic Test Procedure, Feedwater and Main Steam Piping, Including the Secondary Side of the Steam Generators," Revision 0

- **12-THP-4030.STP.205A, "Engineered Safety Features Time Response Test Train A," Revision 13

- **12-THP-4030.STP.205B, "Engineered Safety Features Time Response Test Train B," Revision 12

- **12-THP-4030.STP.217A, "DGAB Load Shedding and Performance," Revision 5

The following findings and observations were identified during these procedure reviews and performance witnessing:

a. During pre-test walkdown of the Procedure ISI.038 test equipment and boundaries, several discrepancies and questions were identified to the licensee hydro engineer who advised that the following were common practice at the facility and had not previously caused problems.

(i) Procedure ISI.038 (and other hydrostatic test procedures reviewed) specified neither standardized nor procedure specific temporary test equipment manifold configurations. As a result, the test manifolds were constructed largely at the discretion of the craft personnel. The manifolds atop the steam generators and at the test pump connections to the feed system contained temporary isolation valves which could isolate test gages and test safety valves.

The temporary test manifold valves were not all included in the procedure valve lineup instructions. While the presence of such valves is not in violation of the ASME Boiler and Pressure Vessel Code, Section XI, it is not a good practice, particularly in the absence of alternative position controls.

(ii) Similarly, neither the temporary test equipment nor system boundary and test lineup valves were controlled by test tags or other methods to ensure that they were correctly installed and positioned and not inadvertently manipulated by personnel not involved in the test.

During subsequent performance of Procedure ISI.038 several related problems occurred. First, a test gage was found isolated by a temporary valve and was reported in Condition Report (CR) 2-CR-11-88-1510. The installation of test equipment to incorrect system connection points was reported in 2-CR-11-88-1572. Finally, when the test pump high pressure hose was disconnected by non-test personnel while pressurized, temporarily aborting the test, this resulted in CR No. 2-CR-11-88-1574.

Acceptability of the licensee's response to the above condition reports will be reviewed as part of the continuing NRC consultant inspection effort.

b. During initial attempts to pressurize the secondary system per Procedure ISI.038, the main steam safety valve gags would not stay in place, causing several of the valves to simmer and/or lift. On several occasions high intensity, high frequency noises accompanied the lifting, indicating the potential for high velocity flows and valve vibration. The licensee corrected the gag installations and proceeded with the test. The problems were apparently not documented for further evaluation and disposition.

During utility sponsored Electric Power Research Institute (EPRI) testing performed in response to NUREG 0737, "Clarification of TMI Action Plan Items," Item II.D.1, valve damage was observed following water actuation/flow in similar spring loaded safety valves supplied by a different vendor than supplied the D.C. Cook plant valves (Reference: EPRI Report No. NP-2770-LD, "EPRI/CE PWR Safety Valve Test Report," March 1983). Following actuation with water, the next steam actuation of the tested valves resulted in severe valve chatter and internal galling (on disassembly and inspection).

The licensee was requested to review the above circumstances and assure that the affected valves were acceptable for service. Initial oral reports from the licensee indicated that the valve vendor had recommended inspection of the valves but that the plant maintenance department had elected to not disassemble the valves. Instead, the valves were to be observed during hot functional testing for indications of misoperation or leakage. However, these observations were apparently not made but will be done during the heatup for plant startup.

Discussions with the maintenance staff indicated that no formal evaluations or plans had been developed for resolving the concerns about potential internal damage. However, at a management meeting on December 13, 1988, the licensee advised that the Shift Technical Advisors had prepared an evaluation report with recommendations and that the valves would be subjected to setpoint testing prior to restart.

The acceptability of the licensee's disposition of the above will be reviewed during the continuing NRC consultant inspection.

c. In conjunction with the valve gag problems, the licensee noted that, although the gags had a machined point on the end of the gag screw, the safety valve stems did not all have countersunk "dimples" to seat the gag screws, contributing to the problem with gags slipping off.

   During test pressurization on November 4, 1988, maintenance and operations personnel were observed attempting to manually drill dimples in the stems of several main steam safety valves. Although this appeared to be a de facto modification to the valve stems, the work was apparently done without formal authorization or instructions. Work was stopped when the valve stem material was found to be too hardened to manually drill and further attempts were not made.

d. Procedure ISI.002 required inspection of the lower reactor vessel head and attachments accessible via the reactor cavity. When the QC inspectors reached the reactor cavity, radiation levels of 5 - 10 R/hr were encountered and that portion of the inspection was aborted. The procedure had not anticipated the incore flux thimbles being positioned in the reactor cavity and provided no prerequisite checks or specific coordination with radiation protection personnel.

Condition Report 2-CR-11-88-1626 was issued documenting the above inadequacies. Licensee disposition of the CR will be reviewed as part of the continuing NRC consultant inspection.

e. No formal method exists to identify and track hydrostatic test deviations requiring retest to completion of the retest. Two examples were observed: (1) during ISI.038, leakage of a main steam dump valve required that a portion of the test volume be isolated until repairs would permit later testing, and (2) radiation levels from partially withdrawn incore detector thimble tubes prevented inspection of the bottom of the reactor vessel per ISI.002.

Unlike other procedures reviewed (e.g., Performance Group tests), the ISI series procedures had no mechanism for separately managing retest requirements. Although the hydro engineer had informal practices used for such situations, these were not controlled by procedure and did not provide assurance that the retests would be performed without the individual's personal initiative.

The cognizant operations production supervisor advised that a method for retest requirement identification and tracking through completion would be established. A departmental memo was issued on December 12, 1988, documenting the current status of open hydro retest items. This item will be followed as part of the continuing NRC consultant inspection.

f. Procedure ISI.002 did not include sufficient forms or space to tabulate quality control inspection findings. As a result, the mechanical joint leaks identified by the test were listed on unsigned and undated tablet paper and attached to the procedure's final data. Upon identification by the NRC consultant, the data was signed and dated by the cognizant QC supervisor who had performed the inspections.

g. During the pre-inspection four hour "soak" for Procedure ISI.002, pressurizer safety valve 45C lifted at approximately 2280 - 2290 psig, about 200 psig lower than required by Technical Specifications. The premature valve actuation caused momentary pressure dips below the 2280 psig minimum hydrostatic test pressure specified by procedure, as indicated on control room recorders. The valve malfunction and operability considerations were documented in Condition Report No. 2-CR-11-88-1628 and will be followed as part of the continuing NRC consultant inspection.

However, ISI.002 included a requirement to re-begin the four hour "soak" if pressure dropped below the minimum test pressure as indicated in the control room. The on-duty test engineer, QA and QC personnel evaluated the conditions, compared control room instruments to local precision test gages, concluded that the actual pressure did not drop below the minimum test pressure and continued with the test.

These actions were considered acceptable by the NRC consultant subject to management review and approval of the observed conditions. But, the anomalous pressure conditions and the subsequent acceptability evaluation were not documented in the procedure, on data sheets, or by condition report. These and similar examples of documentation omissions involving main steam safety valve problems (Subparagraph 12.b above) indicate undesirable practices on the part of test and operations personnel. The operations production supervisor advised that the above circumstances would be reviewed for further action.

h. STPs 205A and B involve extensive simulated and actual operation of valves, dampers, fans, and pumps. The portions of STP.205A and B witnessed (Containment Isolation Phase A and B testing for both trains) had numerous test exceptions and deferrals due to equipment being unavailable because of maintenance or due to equipment malfunctions. In one case, the operator missed two procedure steps, failing to energize containment ventilation heaters which caused their testing to be missed.

   The tests will require a number of retests due largely to equipment unavailability, indicating that the test was perhaps being performed prematurely. Although the Performance Group procedures have a particularly effective method for documenting and tracking test exceptions and retest requirements, the heavy reliance on retests to complete integrated testing appears to be undesirable and possibly avoidable. Licensee tracking and performance of the eventual retests will be followed as part of the continuing inspection.

i. Several aspects of the performance group procedures are quite good. Where jumpers or lifted leads are required, the procedure typically provides detailed, terminal-by-terminal instructions including independent verification provisions. Valve and breaker positions are determined by connecting recorders via simple cable adapters which plug into position indicating light sockets in the control room. The recorders and cables are pre-staged on a special portable, pre-wired test bench. All these features are considered strengths in the licensee's program.

   However, the test equipment installation instructions for Procedures STP.205A and B are inconsistent and rely heavily on the experience of the test technicians and engineers. No specific instructions are provided for connection of test recorders to relays, switches and terminal boards. The test technicians maintained an informal notebook containing lessons learned from past tests and previously successful test connection setups. This information was checked before use by the technicians and test engineer using controlled drawings and the drawings were used during the connection processes. In contrast, the installations required for STP.217A and B were extensively detailed. The absence of detailed connection instructions in the approved procedure provides the potential for error and requires re-determination of the connections each time the test is performed.

j. Additional minor comments and human factors related observations were developed during review of the test procedures.

(i) A number of editorial errors were identified in Procedure ISI.038 (such as incorrect nomenclature for hanger travel stops and valve numbers) and were corrected by procedure change sheet prior to performance.

(ii) The ASME Boiler and Pressure Vessel Code, Section XI provides requirements for limiting hydrostatic test pressures such that system elevation differences will not result in system low points being over-pressurized due to static head.

During review of the ISI-series procedures, it was noted that the licensee does not perform and document a formal test pressure calculation to satisfy the code requirements. The NRC consultant independently calculated the static head contributions to the test pressures for Procedures ISI.038 and ISI.002 and found that the pressures were acceptable.

(iii) Nearly all procedures reviewed used equipment and valve numbers without equipment noun names in action steps, system lineup lists, etc. This provides high potential for operational errors from mis-read or mis-typed numbers without a corresponding noun name.

Where noun names were used, they were frequently inconsistent with the official drawing designations of the equipment. For example, STP.205A referred to the "East ESW Pp" in Step 5.8.28 and the corresponding data sheet step referred to "ESW Pump 1E."

(iv) The general procedure structure relies heavily on separating major actions into separate procedure sections. For example, in STP.217A, each "Test Procedure" subsection in Section 5.0 has an extensive, corresponding "Initial Conditions" subsection in Section 3.0 which provides some of the detailed instructions for setting test conditions. Section 3.0 subsections also have one or more individual attachments or tables which include valve and equipment lineup checklists. However, the Section 5.0 subsections also have some lineup and prerequisite setup instructions with their own attachments and tables and data sheets.

The structure of the procedure drastically affects the flow and utility of the procedure and the test personnel must constantly flip among the procedure sections. This structure appears to have contributed to the missed containment ventilation heater startup step previously discussed in Procedure STP.205 (Subparagraph 12.h above).

(v) Several examples were identified where the results expected from a particular procedure action or the acceptance criteria to be applied are either not stated or are not provided in the same procedure location as the action step. For example, Step 5.6.28 of STP.205A resets solid state protection system relays. Step 5.6.28.6 states, "Attempt to place both S.I. Blocks . . ." but provides no indication (except implication) that the blocks should not actuate or the actions to be taken if they do.

Similarly, in Procedure ISI.002 (and other hydro procedures), the "Test Procedure" section includes no expected results or acceptance criteria and no sign-off blocks for the steps in the text with only sign-off blanks and little or no contextual information. All step and results sign-offs are provided in separate tabular attachments. For example, Data Sheet 1, Step 8.1.11-1 provides for recording primary plant pressure from control room recorders per the same numbered step in the procedure text; several copies of the page were used due to the duration of the test. Step 8.1.12-1 on the same data sheet is a completion sign-off for satisfactorily completing the reactor vessel head O-ring leak detection checks but the data sheet provides only the step number and a signature blank. As a result, several operators repeatedly signed off Step 8.1.12-1 on different dates, apparently mis-reading the block as a final signature for the pressure readings. The O-ring check was only performed once and in the presence of the NRC consultant.

Discussions with licensee personnel determined that a human factors procedures upgrade initiative was just beginning based on prior INPO reviews and that writers' guides and other mechanisms were under development which should address such concerns. The consultant reviewed the writers' guide and examples of procedures already rewritten by the operations department to meet human factors considerations.

No violations, deviations, unresolved or open items were identified.

13. Testing of Plant Modifications (72701, 37828)

A sample of plant modifications (Request for Change (RFC) Packages) and the associated testing were reviewed to determine whether the modifications were properly tested prior to being placed in service. At the time of this inspection, few test procedures had been issued and minimal testing had been accomplished because the selected modifications were still being installed. The following RFC packages were selected for review:

RFC 1978 "Replace Residual Heat Removal (RHR) Heat Exchanger Isolation and Bypass Valves"

RFC 2770 "Modify Turbine Driven Auxiliary Feedwater Pump (TDAFWP) Trip Circuit"

RFC 2873 "Install ATWS Mitigation System Actuation Circuitry" (AMSAC)

RFC 2999 "Replace Incore Detector Thimble Tubes"

Also, **2-OHP-5070.ISI.038, "Inservice Inspection Hydrostatic Test Procedure, Feedwater and Main Steam Piping, Including the Secondary Side of the Steam Generators," Revision 0, was performed as a post modification test for installation of the new steam generators. Inspection results for this test are discussed under Complex Surveillance Testing in Paragraph 12 above.

The inspection of these activities was continuing at the end of the period. One potential problem had been identified and referred to the licensee for review and disposition:

- RFC 2770 involves replacement of a diode in the TDAFWP trip circuity with a resistor, affecting a number of circuit terminals. The initial RFC preoperational test requirements from AEPSC engineering (Memo, J. Schlunt to W. Pauls, September 1, 1988) included various switch, relay contact, and continuity functional tests. The plant design change coordinator initially advised the NRC consultant that equivalent circuit checks had been performed as part of the installation job order (JO 705194) per generic plant procedures and that this and TDAFWP surveillance tests would constitute testing in lieu of the AEPSC test instructions.

  The NRC consultant's review of the job order records and surveillance tests concluded that no documentation of post-installation circuit checkouts was available and that the surveillance tests (to be done later in the outage) did not functionally check all the circuits affected. The design change coordinator subsequently confirmed the consultant's evaluation and advised that the functional checkouts will be performed and documented. These actions will be followed as part of the continuing inspection.

No violations, deviations, unresolved or open items were identified.

14. <u>Safety Assessment/Quality Verification (71707, 93702, 40704, 92700)</u>

The effectiveness of management controls, verification and oversight activities, in the conduct of jobs observed during this inspection, was evaluated.

The inspector frequently attended management and supervisory meetings involving plant status and plans and focusing on proper co-ordination among Departments.

The results of licensee auditing and corrective action programs were routinely monitored by attendance at Problem Assessment Group (PAG) meetings and by review of Condition Reports, Problem Reports, Radiological Deficiency Reports, and security incident reports. As applicable, corrective action program documents were forwarded to NRC Region III technical specialists for information and possible followup evaluation.

a. Two Problem Reports were noted during routine inspector reviews as evidencing sensitivity to potential adverse trends:

   (i) Problem Report 88-812 documented a potential trend, noted by management data review, involving various instances of pumps failing ASME Section XI test criteria due to high (vs. low) pressure differential;

   (ii) Problem Report 88-816 documented an apparent trend, noted in review of other corrective action documentation in order to prepare a "Trend Report", involving degradation of fire seals with implications of tampering/mischief.

b. Two Problem Reports were considered to reflect a technical focus being applied to observations by site Quality Assurance auditors/inspectors:

   (i) Problem Report 88-840 questioned the seismic qualification of two new Unit 2 battery chargers which were installed on shims/spacer plates such that the bearing surface areas were much smaller than that of the other two new chargers.

   (ii) Problem Report 88-916 noted instrument calibration procedure errors as regards the number supplied in the procedure text for modules to be calibrated.

   The ability to emphasize technical safety content in audit and surveillance activities by this group is considered a strength.

c. Proper communication and coordination of activities between and among work groups occasionally appeared to break down, or had the potential to breakdown:

   (i) Problem Report 88-833: following maintenance on the Unit 2 West CCW pump, it remained untested for a period of time which overlapped the removal from service of the 2CD emergency diesel (power for East CCW pump) - this rendered both Unit 2 CCW trains" unavailable" for support of Unit 1 safe shutdown per Appendix R to 10 CFR 50, and applicable compensatory measures were not implemented. This was an exception to the generally good status knowledge about alternate safe shutdown equipment noted in Paragraph 8 above.

(ii) Problem Report 88-908: a Unit 2 AB emergency diesel slow speed test run experienced large voltage and current surges from the voltage regulators because excitation fuses had not been removed. The governing procedure is a Maintenance Procedure which cross-references an Instrument and Control "guideline" to effect fuse removal.

(iii) Problem Report 88-928: Job Order JO 014359 addressed repacking Valve 2-NFA-210-V1, but Valve -V2 was repacked instead based on a presumed shift supervisor approval in the absence of a "clearance."

Careful and accurate intergroup communication and activity coordination were particularly important during this inspection due to the magnitude, complexity and novel nature of activities associated with restoration of Unit 2 to operating status. Items like the above may suggest a need for improved management attention to these complex and/or novel activities. This was discussed with licensee management during the inspection and they were highly responsive. The topic will be the subject of ongoing review.

No violations, deviations, unresolved or open items were identified.

15. Reportable Events (92700)

The inspector reviewed the following Licensee Event Reports (LERs) by means of direct observation, discussions with licensee personnel, and review of records. The review addressed compliance to reporting requirements and, as applicable, that immediate corrective action and appropriate action to prevent recurrence had been accomplished.

a. (Closed) Licensee Event Report (315/87018-LL): Fire rated assemblies and dampers were not inspected as required. This item applied to both Units. The scope of the routine periodic (18-month) fire protection component inspection procedure for fire rated assemblies, dampers and penetration seals was reduced in late 1986 from the historical 100-percent inspection coverage to 10-percent. The 10-percent coverage, however, was permitted only for penetration seals - fire rated assemblies and dampers must be inspected 100-percent. As a consequence, about 90-percent of the fire rated assemblies and dampers were not inspected at the required 18-month interval. Assemblies which should have been inspected on or before March 29, 1987 were not all inspected until August 29, 1987 (the problem was identified August 26). Dampers which should have been inspected by July 1, 1987, were likewise not inspected until August 29, 1987. Counting necessary repairs, the last damper was not completely satisfactory until September 14, 1987.

This problem was the result of an error on the part of a non-licensed supervisor, who incorrectly interpreted the 10-percent inspection provision of Technical Specification 4.7.10.1.c (for penetration

seals) to apply also to 4.7.10.1.a (assemblies) and 4.7.10.1.b (dampers). Appropriate administrative actions were taken.

When the overdue inspections were performed, all fire rated assemblies proved satisfactory, but three dampers failed testing. The failed dampers (all Airstream brand curtain-type dampers) were repaired and passed retesting. Safety evaluations on the dampers which initially failed testing (two in Unit 1 and one in Unit 2) determined that the observed deficiencies did not significantly degrade their respective associated fire barriers.

Failure to perform inspection of 100-percent of specified fire rated assemblies and dampers at the required 18-month interval was contrary to the requirements of Technical Specifications 4.7.10.1.a and 4.7.10.1.b, respectively. When the licensee identified these violations, the uninspected components were all declared inoperable and action initiated to compensate per Technical Specification 3.7.10 by establishing continuous firewatches in affected areas within one hour. Because sixteen additional firewatches were needed, they could not all be called in and posted within the specified one hour. The last post was established five minutes late.

The NRC Enforcement Policy of 10 CFR 2 Appendix C provides that a Notice of Violation will not usually be issued for violations of lesser safety significance which are identified, reported and corrected by the licensee and which are not repetitive of previous similar violations. These criteria appear to apply to these violations. No Notice of Violation is being issued.

b. <u>(Closed) Licensee Event Report (315/88007-LL): Ice built up in ice condenser flow passages due to sublimation.</u> Routine required inspection of the flow passages identified ice buildup beyond 3/8 inch in 36 flow passages. The licensee defines 3/8 inch buildup as evidence of "abnormal degradation" as used in Technical Specifications. A half-dozen previous similar events/voluntary reports show the condition is not completely abnormal. Some 3,072 flow passages exist. These have been analyzed capable of performing adequately up to blockage of 20-percent of the total flow passage area, so the noted degradation is well within analyzed bounds. The licensee manually cleaned the subject flow passages to remove frost/ice buildup. Generic efforts are being pursued jointly with other owners of ice condenser containments to minimize sublimation and redisposition in flow passages.

c. <u>(Closed) Licensee Event Report (315/88011-LL): Failure of bus power indicating light results in reactor trip.</u> On October 19, 1988, at 3:22 p.m., an indicating light bulb shorted and relays in the affected input bay de-energized, including the reactor coolant pump breaker position logic circuit relay. With reactor power above 50-percent (it was at 90-percent) a reactor trip resulted. All significant post-trip functions operated properly, and operator responses were correct. Required notifications were made. The faulted bulb and socket assembly, which had no previous failure history, were replaced. A blown fuse was also replaced, potentially affected protective circuitry was tested and found damage-free, and the Unit was returned to service.

d. (Closed) Licensee Event Report (316/85020-LL): Inoperable fire damper. A curtain-type fire damper was found upon periodic inspection to have two lower sections broken loose. With no specific event time identifiable, the licensee presumed the condition had been present more than the allowable ACTION time for establishing a fire watch. The LER was reported on that basis as an interim report pending an engineering evaluation. The evaluation subsequently concluded, based on damper location and associated automatic area fire detection and suppression systems, that the presumed Technical Specification violation (failure to implement timely compensatory measures for an "inoperable" damper) had not occurred. By letter dated June 4, 1987, this LER was withdrawn.

e. (Closed) Licensee Event Report (316/85042-LL): An hourly inspection of an inoperable fire barrier was three minutes late due to a gate latching mechanism jamming and preventing the inspector from completing his tour on time. Fire detection and suppression equipment remained operable in the affected area throughout. This event is an example of a Violation identified, reported and corrected by the licensee, which was neither repetitive nor of special safety significance. As such, in accordance with NRC policy under 10 CFR 2, Appendix C, no Notice of Violation is being issued.

f. (Closed) Licensee Event Report (316/86009-LL): Containment Type B and C Leakage exceeded the LCO value due to degradation of isolation valve seating surfaces. On March 15, 1986, the as-found results of Type B and C testing performed on a containment isolation check valve (CS-321) in the chemical and volume control system reflected an unquantifiable leakage rate. This resulted in the cumulative leakage for all penetrations and valves subject to Type B and C tests exceeding the allowed limit (0.60 La) of Technical Specification 3.6.1.2.b.

The root cause of the valve's failure to maintain an adequate seal was a misalignment between the disk and valve seat. Repair attempts were unsuccessful; therefore, the valve was replaced with a new valve supplied by a different manufacturer.

The new valve utilizes a more efficient closure mechanism by eliminating the linkage assembly between the disk and hinge. Type B and C testing performed on CS-321 after replacement resulted in an as-left leakage of 1000 standard cubic centimeters per minute (SCCM). This is well below the applicable ISI limit of 1800 SCCM. Furthermore, the new valve was inspected at full system pressure on March 16, 1987 and zero leakage was observed. Type B and C testing performed during the present outage yielded an as-found leakage of 200 SCCM.

g. <u>(Closed) Licensee Event Report (316/86015-LL)</u>: Inoperable fire seals. This report documents the discovery of 24 fire barrier penetrations lacking sealant. In 22 cases, the penetrations had not previously been identified as requiring sealant, and controls to inspect and maintain them did not exist. Two examples involved penetrations from which sealant had apparently been removed following an earlier satisfactory inspection.

The LER identifies six previous similar events. NRC had independently identified fourteen similar events (including five of the six noted in this LER) as relating to inoperable fire barrier penetrations, and an Unresolved Item (315/86022-04; 316/86022-04) was developed to track NRC Region III review of this issue. The Unresolved Item has been subjected to some additional inspection (Inspection Reports No. 315/87016(DRS); 316/87016(DRS) but still more inspection is planned. This LER will be "closed" and generic review performed under the still "open" Unresolved Item.

h. <u>(Closed) Licensee Event Report (316/86019-LL)</u>: A required hourly firewatch tour was missed due to tour personnel error - the wrong room was being toured. With fire door No. 470 inoperable, hourly tours of the Unit 2 Boron Injection Tank (BIT) room, containing the door, were required. Due to poor documentation, poor shift turnover, and lack of clear door identification marking, a newly arriving contract firewatch began tours of the Unit 1 BIT room instead of the Unit 2 room. This error was discovered by a supervisor during the second tour of the Unit 1 room, by which time the Unit 2 room had not been inspected for one hour and 53 minutes. The situation was corrected by re-commencement of the proper tours. Administrative actions were taken with the involved individuals, and identification numbers were restored to the doors. A subsequent safety evaluation by the licensee concluded the event did not involve a significant safety concern or unreviewed safety question. It did involve a Violation of Technical Specification requirements for performing hourly tours. This is another example of a violation identified, reported and corrected by the licensee which lacked special safety significance. There having been a number of previous similar events, this problem was considered repetitive, and a Notice of Violation was issued in 1987 (Violation 315/87016-02; 316/87016-02) after NRC review of the referenced similar events. Corrective and preventive actions have since proven effective, so no separate Notice of Violation is being issued on closure of this item.

i. <u>(Closed) Licensee Event Report (316/87008-LL)</u>: Unit 2 tripped from 19-percent power during a startup on July 22, 1987. The steam generator levels were being controlled manually when a feedwater pump delta-P controller malfunction caused overfeeding of the steam generators and a high water level turbine trip and reactor trip. Plant response to the trip signal was nominal. The suspect controller was tested immediately following the event but the malfunction could not be reproduced. Still, it was replaced with a new controller, and the plant was returned to service.

j. (Closed) LER 316/88008-LL: A fire door was determined to be inoperable without the required continuous fire watch due to a labeling problem and personnel error. A roll up fire door to the West Motor Driven Auxiliary Feedwater Pump (WMDAFP) room was made inoperable when a hose was placed through the doorway for a hydrostatic test. The door was then closed down on the hose and the sliding missile door (uninhibited by the hose) was closed over the hose. Due to inadequate labeling of the fire door and the fact that the missile door was previously the fire door until a design change installed the roll up door; the involved persons did not recognize the inoperability and no fire watch was posted.

Consequently, a routine fire protection tour identified the hose through the doorway of the WMDAFP roll up fire door and a roving fire watch was subsequently established. The fire door was subsequently restored to an operable status. It was subsequently identified that a continuous fire watch should have been posted. The failure to post a continuous fire watch was caused by personnel error.

The door labeling problem has been corrected. A guidance letter was issued to persons involved with fire watch postings to stress the importance of positively identifying whether a roving or continuous fire watch is required whenever they are involved with an inoperable fire door.

This event is an example of a violation that was determined to have met the tests of 10 CFR Part 2, Appendix C; consequently, no Notice of Violation will be issued and this matter is considered closed.

No violations, deviations, unresolved or open items were identified.

16. NRC Information Notices (71707)

The inspector reviewed the NRC communications listed below and verified that: the licensee has received the correspondence; the correspondence was reviewed by appropriate management representatives; a written response was submitted if required; and, plant-specific actions were taken as described in the licensee's response.

The inspector reviewed licensee actions in response to NRC Information Notice 85-18, "Failures of Undervoltage Output Circuit Boards in Westinghouse-Designed Solid State Protection System." This review was prompted by a request from the Office of Nuclear Reactor Regulation (NRR) to provide a summary description of licensee actions (in support of an NRR survey) on Westinghouse Technical Bulletin NSID-T8-85-16. The Technical Bulletin addressed the same issue as the Information Notice, and the licensee's Information Notice actions were deemed to address the Technical Bulletin as well. The issue was one of prevention or detection methods to assure no undetected output circuit board failures would occur. Westinghouse proposed installation of a redesigned circuit board with an integral fusible link, and recommended the circuit be physically removed, whenever possible, during maintenance. The licensee chose to implement administrative controls rather than a design change. The redesigned board would not prevent output transistor failure, was not an identical substitute, and would introduce an additional failure mode involving the fusible link. Controls were placed in the three test procedures and the single maintenance procedure determined to be related to the issue. These assure the board functions properly after any interaction with it.

NRC Region III selected the additional Information Notices listed below for inspection review. For each Information Notice the inspector verified that the Information Notice was reviewed by management representatives, a written response was submitted if required, and plant-specific actions were taken or scheduled as described.

a. (Closed) NRC Information Notice 88-46 (Supplement 1): "Licensee Report of Defective Refurbished Circuit Breakers." The licensee review dated October 6, 1988, documents that normal practice is to procure all molded case circuit breakers as nuclear grade regardless of the application. It is also the licensee's practice that all nuclear grade materials be shipped directly from locations specified on the "Qualified Suppliers List." Thus, by specifying the shipping point, the local supplier is avoided.

b. (Closed) NRC Information Notice 88-51: "Failures Of Main Steam Isolation Valves." The licensee review dated August 14, 1988 documents that since D.C. Cook's main steam isolation valves operate on steam from the "system" to close and isolate the steam lines, their capability to operate as presented in the safety analysis is not affected. Furthermore, post-maintenance testing is mandated following any maintenance, including packing maintenance, which includes full stroke and timing of the emergency closing system.

c. (Closed) NRC Information Notice 88-55: "Potential Problems caused By Single Failure Of An Engineered Safety Feature Swing Bus." The licensee review dated October 27, 1988 documents that the plant should not experience the failure potential described in the Information Notice. The plant has separate power buses and control power buses for each train. The isolation and duplication of trains precludes this type of potential failure involving a swing bus.

d. (Closed) NRC Information Notice 88-01: "Safety Injection Pipe Failure." This Information Notice has been superseded by NRC Bulletin No. 88-08: "Thermal Stresses in Piping Connected to Reactor Coolant Systems." The Bulletin remains open. The inspector specifically noted that the licensee had already agreed to perform an inspection of the Unit 2 pressurizer surge line piping in the scope of his review, prior to the Bulletin calling attention to potential problems with this piping.

e. (Closed) NRC Information Notice 87-59: "Potential RHR Pump Loss." This Information Notice has been superseded by NRC Bulletin No. 88-04: "Safety-Related Pump Loss." The Information Notice and Bulletin address concerns regarding the design of the minimum flow (miniflow) recirculation line configuration for the RHR pumps.

The first concern involves the potential for dead-heading one or more pumps in safety-related systems that have: (a) a miniflow line common to two or more pumps; or (b) other piping configurations that do not preclude pump to pump interaction during miniflow operation. The second concern involves whether or not the installed miniflow capacity is adequate for even a single pump in operation.

The licensee identified a potential problem dealing with the open cross-tie joining the two RHR discharge lines upstream of the miniflow circuit. This could cause the two miniflow circuits to act in parallel rather than independently. This in turn could cause the weaker pump to be shut off by the stronger pump.

The licensee was finalizing an analysis for submittal to the NRC Office of Nuclear Reactor Regulation (NRR) when Bulletin 88-04 was issued. NRR is currently evaluating the analysis for 2 loop injection as a result of cross-tie closure. Completion of the review is expected in January 1989. As an interim measure, an analysis was performed which determined there is no short term potential for dead-heading to occur with the currently installed pump set.

Further, the existing pumps have been routinely tested using only their installed mini-flow lines. The absence of damage from this practice is evidence that the installed mini-flow capacity is adequate. This addresses the second concern. The Bulletin remains open.

f. (Closed) Information Notice 88-09: "Reduced Reliability of Steam Driven Auxiliary Feedwater Pumps Caused by Instability of Woodward PG-PL Type Governors." The licensee documentation dated April 19, 1988, states that a review of all auxiliary feedwater system problems was conducted by plant and AEPSC (Corporate Engineering) personnel.

The result of the review has been the implementation of better preventive maintenance practices, including lubricating the governor linkage at intervals not to exceed 12 months; disassembling, inspecting, and repairing the governor valve every refueling outage; performing surveillances with conditions identical to that preceding an actual demand; and completely replacing the governor with a spare at intervals not to exceed four years.

No violations, deviations, unresolved or open items were identified.

17. 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 3.b.

18. Management Interview (30703)

The inspectors met with licensee representatives (denoted in Paragraph 1) on December 13 and 28, 1988 to discuss the scope and findings of the inspection. In addition, the inspectors also discussed the likely informational content of the inspection report with regard to documents or processes reviewed by the inspector during the inspection. The licensee did not identify any such documents/processes as proprietary.

The following items were specifically discussed:

a. An Open Item relating to licensee abandonment plans for MOV local position dials (Paragraph 3.b);

b. the licensee's commitment to use no "suspect" DB-50 breaker until its acceptability has been verified (Paragraph 3.c);

c. the licensee's plans for 100-percent cleanup of Unit 2 repair project contaminated material laydown areas in operating areas before startup (Paragraph 5.b);

d. timely and effective responses to Emergency Plan (Paragraph 9) and Security (Paragraph 10) events;

e. the possible need for increased management attention to conduct of complex, infrequent activities (especially those involving extensive intergroup coordination) as evidenced by problems occurring during such activities (Paragraphs 12.a, 12.d, 12.g and 14.c).