U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Reports No. 50-315/89029(DRP); 50-316/89029(DRP)

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

Licensee: 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: October 4 through November 16, 1989

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

12/6/89
Date

Inspection Summary

Inspection on October 4 thru November 16, 1989 (Report No. 50-315/89029(DRP); No. 50-316/89029(DRP))

Areas Inspected: Routine unannounced inspection by Regional and resident inspectors of: actions on previously identified items; plant operations; radiological controls; maintenance; surveillance; security; safety assessment/quality verification; engineering and technical support; reportable events; Bulletins, Notices and Generic Letters; Allegations; and, NRC Region III requests. In addition, on November 16, 1989, a Management Meeting was conducted in NRC Region III, to discuss operations and management issues and a second meeting was conducted regarding licensed operator training. The following Safety Issues Management System (SIMS) items were reviewed, with the indicated results: (Open) Generic Safety Issue GSI 93 and Generic Letter GL-88-03 concerning steam binding of auxiliary feedwater pumps.

Results: Of the 13 areas inspected, no violations or deviations were identified in 12 areas. One violation was identified (Level IV - operation in MODE 1 with neither ECCS subsystem OPERABLE - Paragraph 10.g) in the remaining area.

The inspection disclosed weaknesses in the licensee's control of work activities, to ensure such activities are confined to a single safety "Train." This is reflected in the Notice of Violation and was the focus of the November 16, 1989, Management Meeting.

DETAILS

1. Persons Contacted

   a. Inspection: October 4 - November 16, 1989

   *A. Blind, Plant Manager
   *J. Rutkowski, Assistant Plant Manager, Technical Support
   L. Gibson, Assistant Plant Manager, Projects
   *K. Baker, Assistant Plant Manager, Production
   B. Svensson, Executive Staff Assistant
   J. Sampson, Operations Superintendent
   E. Morse, QC/NDE General Supervisor
   T. Beilman, Maintenance Superintendent
   *J. Droste, Technical Superintendent, Engineering
   T. Postlewait, Design Changes, Superintendent
   L. Matthias, Administrative Superintendent
   J. Wojcik, Technical Superintendent, Physical Sciences
   M. Horvath, Quality Assurance Supervisor
   D. Loope, Radiation Protection Supervisor

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

   *Denotes some of the personnel attending the Management Interview on November 17, 1989.

   b. Management Meeting - November 16, 1989

   Licensee

   M. P. Alexich, Vice President, Nuclear Operations
   A. A. Blind, Plant Manager
   P. A. Barrett, Director of Quality Assurance
   S. J. Brewer, Nuclear Safety and Licensing
   K. R. Baker, Assistant Plant Manager, Production

   NRC

   M. J. Clausen, Deputy Director, Division of Reactor Projects
   W. L. Axelson, Chief, Projects Branch 2
   B. L. Burgess, Chief, Projects Section 2A
   B. L. Jorgensen, Senior Resident Inspector
   E. R. Schweibinz, Project Engineer

2. Actions on Previously Identified Items (92701)

   As a result of a special safety inspection conducted by an NRC Augmented Inspection Team (AIT) documented in NRC Inspection Reports No. 50-315/89025(DRSS); No. 50-316/89025(DRSS), and concerning the

Unit 2 reactor trip of August 14, 1989, the licensee responded to the four issues identified in Paragraph 9 of the inspection report by a letter (AEP:NRC:1090J) dated October 25, 1989.

Item 9.a: The failure mode of the silicon controlled rectifier (SCR 209) was confirmed as random.

Item 9.b: The loads supplied by all CRIDs have or will have electrical independence such that a failure of a single CRID will not cause a loss of all channels of some parameter (such as steam generator wide range level indication) monitored in the control room.

Item 9.c: Engineering guidelines are in place and a procedure will be issued for testing CRID Inverters prior to switching from the alternate to normal power supplies. The preventive maintenance procedure in effect for the CRID Inverter will be expanded to include the Static Transfer Switch.

Item 9.d: Finally, training was upgraded on operation of the AMSAC (ATWS Mitigating system actuation circuitry) system.

The inspector had no further questions on these matters. They are considered closed.

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

3. <u>Operational Safety Verification (71707, 71710, 42700)</u>

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. The Plant Manager, Assistant Plant Manager-Production, and the Operations Superintendent were well-informed on the overall status of the plant, made frequent visits to the control rooms, and regularly toured the plant.

Evaluation, corrective action, and response to off-normal conditions or events, if any, were examined. This included compliance with 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. Both Unit 1 and Unit 2 were in continuous routine power operation throughout the inspection period. Operation was at full rated power with a few brief exceptions of reduced power operations to permit inspection or maintenance of the main feed pumps.

b. On October 12, 1989, a non-licensed auxiliary equipment operator (AEO) assigned to the Unit 1 turbine building tour was discovered to have logged activities (area inspections) which were not performed. A pattern of increasing nonperformance over the preceding week was identified via cross-checks between tour logsheets and computerized access records. The individual was discharged effective October 16, 1989.

An audit of required tour performance by numerous other AEO's identified occasional discrepancies but no chronic problems. The licensee enhanced monitoring of the area and evaluated programmatic changes to clarify how tours are to be performed and logged. Minimum shift crew requirements were not violated. However, the inspector identified that the AEO described above failed to make some checks committed to in the licensee's response to Generic Letter 88-03 (e.g., see Paragraph 11).

The licensee's procedure (OHI-4013, "Operators: Authorities and Responsibilities") for shift operations and duties, however, was violated. Since adherence to this procedure is a requirement of Technical Specification 6.8.1.a, through reference to Regulatory Guide 1.33, Appendix A - 1972, failure to perform the specified area tours is considered a violation of the referenced Technical Specification.

This violation was identified and corrected by the licensee. It was not highly safety significant, nor was it repetitive of previous violations. In accordance with normal practice as established in the NRC Enforcement Policy (10 CFR2, Appendix C) no Notice of Violation is being issued on this matter. Some additional NRC reviews to verify corrective actions and associated issues is anticipated.

c. On November10, 1989, the licensee determined that a previously identified problem, which was undergoing an engineering and safety evaluation, represented a condition outside the plant design basis and was reportable. Required notifications were made.

The problem is described further in Paragraph 6.f of this inspection report and involved a licensee Inservice Test (IST) of the Unit 2 Turbine Driven Auxiliary Feedpump.

d. Twelve hour operating shift schedule has been developed. The Target date to have this in effect is January 1, 1990. The inspector was provided with a draft rotation schedule encompassing a 15-week cycle of 8-hour training shifts and 12-hour operating shifts. Overtime backup was considered in the schedule. The inspector discussed the need to consider two issues in implementing the revised rotation. First, administrative control of overtime will need to be considered and, if necessary, changes made in the methods for assuring compliance to applicable limitations. Second, commitments and schedules which currently specify three-times-per-day activities will need review and appropriate adjustments.

e. The licensee is developing a computerized "clearance permit" database system, which the inspector reviewed. The ultimate goal is to produce an automatic system, providing the user with an extensive detailed summary of individual components and systems. The database will supply the information necessary to tag out entire systems, subsystems, or components. It will have the capability to cross-check for other clearances written on equipment with a pre-existing clearance.

A control room team has investigated all control switches in both units' control rooms, verifying the switches against existing plant data, drawings, and other information applicable to the particular control.

Computer generated "standards" have been sent to each shift crew for a quality assurance check. Once this is completed the approved Clearances will be officially accepted as standards in the computer database.

f. 12 OHP 4021.019.001 "Operation of the Essential Service Water (ESW) System." The inspector performed a walkdown of a section of the ESW system as described in Data/Signoff Sheet 5.2, "ESW, Loop 1W Normal Valve Lineup." Prior to the walkdown, the change sheets associated with the procedure were reviewed to assure proper inclusion into selected portions of the procedure. Approximately 50 valves were inspected; all were found correctly positioned.

Some minor discrepancies were noted between the valve number as stated on the data sheet and the valve number printed on the tag attached to the valve. For example, 1-WPI-712-V11W on the data sheet corresponded to 1-WPI-712-V1 on the valve's tag. This and other differences were given to the appropriate onsite group for followup.

Other observations unrelated to the ESW system were identified during the walkdown and also relayed to plant supervisory staff. One involved damage to a 1/2 inch line connected to 1-CPI-450-V1 (component cooling water to miscellaneous pressure indicator). The line appeared to have been stepped on; it was bent down and flattened at a fitting joint. Also, on the platform grating below the valve, a lock and chain were lying unattached to any piece of equipment.

One final observation relayed to the plant staff was a loose, ceiling-mount, adjustable ring hanger for a length of pipe just upstream of the Turbine Room Sump overflow discharge line, located in the screen wash pump room.

One violation (not cited) and no deviations, unresolved or open items were identified.

4. Radiological Controls (71707)

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.

On November 11, 1989, the licensee reported, then subsequently withdrew, an Emergency Notification System (ENS) notification. During setup for an at-power purge of Unit 2 containment, a procedure deficiency was discovered which the duty Shift Supervisor decided might cause substantial potential for loss of control of the release of radioactive material. On that basis, the ENS notification was made.

The problem involved a "note" in data/alignment Sheet No. 3 of the purge procedure, which stated certain subsequent steps were "not applicable" in MODEs 1 through 4. This was in error. The referenced steps involved verification of operability of radiation monitor Trains A and B, and placing the monitor output circuits in "Normal". Failing these actions, purge would not isolate on containment high radiation as designed.

The licensee had not purged in MODEs 1-4 in several years. An alternate procedure for containment pressure relief, using different lines, was verified as correctly aligning the radiation monitoring system. Upon further evaluation of the subject procedures the licensee determined that the identified discrepancy alone (as stated in 10 CFR 50.72 for ENS notification) would not have caused uncontrolled release of radioactive material. Two other statements in the same procedure directly contradict the erroneous statement, and the frequent operation of the pressure relief system has made operators familiar with the necessary realignment of the radiation monitoring system. On these bases, the ENS notification was withdrawn later the same day.

The procedure errors, which occurred during a March 1989 revision, were corrected. The inspector verified the correction and that no use was ever made of the procedure with the error present. The inspector also reviewed the system and the licensee's evaluation and agreed with the licensee's assessment. This review included verification that, even had the error been implemented, containment purge isolation from safety injection and from high containment pressure would both have been unaffected.

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

5. Maintenance (62703, 42700)

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 No. A011391, "Disconnect annunciator drop 69 on panel 122, titled, Individual Hotwell or Miscellaneous Drain Tank or Feed Pump Turbine Condenser Conductivity High.' Reconnect when notified by Design Change Coordinator." The activity was performed as part of the ongoing effort to attain a "black board" status in the control room. The system is currently under a design change (RFC - "Request for Change") which has not yet been closed out.

   The annunciator was disconnected because of recurring problems with the detector and the cation bed, which would result in frequent alarms in the control room. The associated alarm response procedure lists no automatic actions and requires the Chemical Lab to investigate. The system initiated numerous false alarms which led to its disconnect. The annunciator will be disabled until it is made to function properly. Any increase in secondary conductivity would be seen in the steam generator blowdown samples, which are monitored on a shiftly basis.

b. Job Order No. A002121, "Repack 1-IMO-204 with Chesterton Packing; weld leakoff line." The work was performed on the valve (spray additive tank outlet) using procedure **12 MHP-SP-130, "Installation Procedure for A.,W. Chesterton Nuclear Valve Sealing System." The inspector saw no problems with the work being performed. It was noted, however, that the procedure was inconsistent as regarded dimensions; sometimes they were provided, sometimes not. One example pertained to stuffing box data. Stem outer diameter and box inner diameter were simply listed as 0.750 and 1.250 respectively, without stipulating units (e.g. inches, centimeters).

c. Job Order No. A012011, "Investigate and repair valve 1-FRV-256 (Unit 1 turbine-driven auxiliary feedwater pump test line isolation valve); valve leaks by when closed." This activity utilized Procedure **12 MHP 5021.001.012, "Hammel Dahl V-500 Series Globe and Angle Valves." The valve disc was ground to remove surface cutting and was lapped and blued to its seat.

d. Job Order No. B010940, "Fabricate and erect security enclosure for Unit 2 "N Train" battery and associated switch gear."

e. Job Order No. B001217, "Repair control air line hanger/support where damaged above tray 2A1C6."

f. Job Order No. A011251, "Fabricate and install security cage for Unit 1 panel and charger." The work was being performed as directed by a Request For Change (RFC 12-3019) to upgrade the "N train" batteries and support equipment. Two procedures were being followed for the job, one of which (**12 MHP 5021.001.006) provided instructions for the fabrication and erection of structural steel, and the other (**12 MHP 5021.001.003) provided instructions for anchor bolt installation. Review of these items identified one minor problem; wall mounted anchors had to be installed one inch lower than originally intended due to a surveying error. This discrepancy was properly documented and approved in an attachment to the relevant procedure noted above.

g. Job Order No. B003162, "Inspect and measure orifice No. 2-FFX-253 Unit 2 Turbine Driven Auxiliary Feedpump test line orifice." The subject Job Order was written in response to the condition discussed in Paragraph 6.f of this report.

   The bolts installed at the orifice flange (2-FFX-253) were found smaller in diameter than stated on the associated isometric drawing (3/4 inch versus 7/8 inch), and the flexitallic gaskets were sized for 1500 lbs. versus 900 lbs. Both the bolts and gaskets were replaced with those of the correct size. The other Auxiliary Feedpump orifices were checked, and another case involving undersized studs was found in the Unit 2 East Motor Driven Auxiliary Feedpump Room. Those studs were also immediately replaced with the correct size. Separate corrective action documents were initiated on each discrepancy, to ensure root cause and significance evaluations are performed. Depending on the findings of those evaluations, further inspection followup may occur.

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

6. <u>Surveillance (61726, 42700)</u>

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. **1 IHP 4030 STP.100.001, "Response Time Testing of the Reactor Protection System Sensors." The inspector observed various portions of this multifaceted test, including the Reactor Coolant RTDs and selected Foxboro pressure/flow transmitters. The testing was conducted by a contractor using plant-approved (but contractor-developed) procedures and with all electrical connections, switching, and disconnections by assigned plant Instrument and Control staff.

b. **2 IHP 4030 STP.122, "Steam Generator 2 and 4 Mismatch Protection Set II Surveillance Test (Monthly)." The inspector noted plant Quality Control was present for this test to independently assess test performance and results.

c. **2 IHP 4030 STP.134, "Reactor Coolant Pump No. 3 Underfrequency, Bus 2A Surveillance Test (Monthly)."

d. **12 THP 6010 RAD.1602, "Liquid Process Monitor Detector Calibration." The inspector witnessed part of the calibration process for the Unit 2 East essential service water header (instrument R-20) and did not observe a problem.

e. **12 THP 6030 IMP.012, "Radiation Monitoring System Calibration - Air/Liquid/Gas." Discussions with the technicians performing this test on process monitor R-19 in Unit 2 (Steam Generator Blowdown Sampler) revealed a defective circuit card had earlier been identified and replaced. The inspector questioned the whereabouts of the associated repair Job Order, which was not present, and was referred to the I&C office. A Job Order was verified to exist (No. 000253) documenting the repair and accounting for traceability of the new part.

f. **2 OHP 4030 STP.017T, "Turbine Driven Auxiliary Feedwater Test." The subject test was performed during an NRC review (ref. NRC Inspection Report No. 50-315/89028(DRS); No. 50-316/89028(DRS) of the licensee's pump In-Service testing (IST) program. During the test, the NRC auditor noted that the process flow instruments (2-FFS-258 and 2-FFS-260) read 550 gpm while the pressure

differential across the 3-inch test line orifice (2-FFX-253) equated to 700 gpm. The flow instruments associated with both the process orifice and test orifice were checked and found to be in calibration and the instrument lines were verified to be free of blockage. The test was rerun and the discrepancy still existed. At that point it was determined that the dimensions listed for one of the orifices could be incorrect.

The test line orifice was disconnected and measured and found to be correct. The process orifice could not be disconnected because of location, but based on calculations, it is believed this orifice is larger than design. The associated "flow retention" switches were therefore reset to a lower setpoint, proportionate to the observed flow mismatch.

The significance (root cause and potential consequences) of this problem remained under investigation with NRC Region III at the conclusion of this inspection, but are expected to be discussed in the Inspection Report referenced above.

g. **1 OHP 4030 STP.017T, "Turbine Driven Auxiliary Feedwater Systems Test." This test was conducted for the purpose of restoring the system to service following maintenance on the associated test valve 1-FRV-256 (ref. Paragraph 5.c above) and as a routine monthly test. During the test, the inspector observed test gauge TG-097, which is used to measure test flow (measure differential pressure across an orifice in the test line) was quite erratic and had a small leak out the low-pressure vent. This raised a question about instrument accuracy which was relayed to the test engineering group onsite. They determined that the test should be rerun (initial data showed unexpectedly high pump delta-P) with the test gauge pulse-dampened and the vent not leaking. The test then produced satisfactory results.

h. Problem Report (PR) 89-887, "2 MRV-210 main steam stop valve for No. 1 Steam Generator, Unit 2 failed initial valve cycle time." The problem involved a slow stroke time (5.45-seconds versus the Technical Specification 5.00-second limit) for the subject valve, using its "Train B" dump valve. The valve met the 5-second stroke time limit (2.52-seconds) when tested with its "Train A" dump valve.

The event was initially classified as a Condition Report, but was later upgraded when the licensee was asked to review the event against NRC reportability requirements.

An investigation against 10 CFR 50.73, "Licensee Event Report (LER) system," and NUREG-1022 and NUREG-1022, Supplement 1, both of which elaborated on the LER rule, was performed. The investigation found the event to be nonreportable, since 2-MRV-210 met the full requirements of the Technical Specification ACTION statement and since there was no evidence to believe the valve was inoperable prior to the surveillance test.

Condensation accumulation in the piping associated with the "Train B" dump valve is believed to be the cause of the problem. Formation of a "water slug" could impede steam flow and thus the closure time of 2-MRV-210. The licensee intends to inspect the valve's internals during the next outage of sufficient duration to determine if the drain tube configuration associated with the valve is in any way damaged or clogged.

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

7. 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.

On November 1, 1989, the inspector was notified that licensee Quality Assurance had found an onsite contractor (who provided background investigative services for personnel who are granted unescorted access to the plant) could not demonstrate validity of all of the information provided in some individual screening reports. The finding was referred to NRC Region III Security personnel for follow up.

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

8. Safety Assessment/Quality Verification (37701, 38702, 40704, 92720)

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. The inspector reviewed safety valve testing using the Trevitest method, pursuant to a question from NRC Region III. The concern related to the performance of an appropriate review to determine whether testing via this method would result in an "unreviewed

safety question" as defined in 10 CFR 50.59. Specifically, if the testing should be permitted or performed in plant MODEs not originally envisioned, does there exist a safety evaluation under 10 CFR 50.59 to substantiate its acceptability?

Safety valve testing via the Trevitest method as performed at D.C. Cook plant is limited to secondary system valves. This testing is governed by procedure **12 MHP 4030 STP.008, which permits testing in MODEs 1, 2 and 3. This procedure was approved at Plant Nuclear Safety Review Committee (PNSRC) meeting No. 2273 on June 15, 1989, at which time PNSRC decided a 50.59 unreviewed safety question determination was not required. Further investigation showed that the current procedure was decended from an earlier version numbered **12 MHP SP.126. The earlier procedure was subjected to a 10 CFR 50.59 safety evaluation dated June 22, 1987, which the inspector reviewed.

The safety evaluation was imprecise with respect to carefully covering all aspects of 10 CFR 50.59. For example, the Trevitest method does not increase either the frequency of testing or the probability a given valve will fail to reclose during any specific test, but the safety evaluation does not explicitly address any potential for changing the probability of occurrence of an analyzed event.

On the other hand, the potentials for changing the nature or magnitude of analyzed events were more explicitly evaluated. Further, the adaptability of the method to other than "during scheduled outages" (original FSAR, Section 10.2.4) was recognized, was determined to be bounded by the MODE 3 case, and the FSAR was updated to read "prior to or during plant outages."

The safety evaluation relied upon certain procedural prerequisites or limitations. For instance, no seismic evaluation was deemed necessary due to procedure restrictions limiting testing to one valve at a time and requiring the consideration of the valve in test was "inoperable." Test equipment is prohibited from being powered off a safety related (Class 1E) bus.

The inspector concluded that the licensee's determination, while not as explicit as desired in all details, was correct - performing the test pursuant to the procedure as approved does not constitute a 10 CFR 50.59 unreviewed safety question.

The above information was conveyed to the Region III requester.

b. Some good technical findings by the licensee's Quality Assurance (QA) organization resulted in the issuance of Problem Reports (PR). Three worth noting are PR 89-1177, PR 89-1222, and PR 89-1184.

Problem Report 89-1177 documents a finding that some flow instruments used for the Inservice Testing Pump Program have a full scale range greater than that specified by ASME XI (3.65 vs. 3.0 times reference or less).

Problem Report 89-122 discusses a finding where elements of a Technical Specification defined "reactor trip response time" were not incorporated into the associated response time procedure. Specifically, gripper coil voltage decay time had been deleted.

Lastly, Problem Report 89-1184 describes a technically inaccurate change to a Maintenance Department procedure. The change added instructions for replacing a Shunt Trip Attachment (STA) which were identical to those for replacing an Under Voltage Trip Attachment (UVTA). These pieces of equipment differ and require separate sets of instructions for replacement.

c. The licensee announced an onsite reorganization plan, effective November 1, 1989, which is intended to produce an improved emphasis on maintenance, and on project management and support. Significant elements of the reorganization include assembly of a new Projects division, from various existing departments, headed by an Assistant Plant Manager. The Projects division will be responsible for design changes, scheduling of major or long lead-time projects and outages, and construction and contractor management. The Administration division will no longer be headed by an Assistant Plant Manager, but some of its elements will be reporting directly to the Plant Manager; this includes the independent Safety and Assessment Department. The Production and Technical Support divisions will remain, with some lesser internal restructuring, and will be headed by Assistant Plant Managers. A number of personnel reassignments or rotations occurred within these groups, the most significant being promotion of the former Operations Department Superintendent to Assistant Plant Manager-Production. The reorganization was discussed at the Management Meeting on November 16, 1989 (Paragraph 14). A review of select personnel qualifications was incomplete at the conclusion of the inspection. The results of this review will be included in a future report.

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

9. <u>Engineering and Technical Support (37701, 41701, 93701)</u>

The inspector monitored engineering and technical support activities at the site and, on occasion, as provided to the site from the corporate office. The purpose of this monitoring was to assess the adequacy of these functions in contributing properly to other functions such as operations, maintenance, testing, training, fire protection and configuration management.

a. Unit 2 emergency diesel generator 2CD failed to load during a test run on September 18, 1989. The test was being performed, in part, to verify proper installation of design change No. RFC-DC-12-2864, which will provide "slow speed" start capability to all four onsite diesels. As part of the design, the field flash to the generator exciter rotor is disabled and excitation depends on residual magnetism in the rotor. This proved inadequate during the subject test - a condition apparently not forseen during original design and not detected in previous testing. Some previous testing did not include observing generator performance as opposed to diesel engine performance; some testing apparently occurred with the original rotor starting position coincidently aligned such that excitation was adequate, and the generator loaded successfully.

The problem was documented on Problem Report 89-1041, the "slow speed" circuits were all disabled, and a redesign is under evaluation. The diesel emergency functions were not adversely affected by this design oversight.

b. Problem Report 89-1194, written on October 26, 1989, documented discovery of the fact that Unit 2 MODE 4 and 5 shutdown boron curves in the Technical Data Book (Figure 4.5) lacked appropriate safety margin for postulated boron dilution accidents while on residual heat removal. As an immediate, interim corrective action, instructions were issued to add 300 gpm to the concentration determed from the referenced Figure, should MODE 4 or 5 operation occur before new curves could be generated. No such shutdown was actually necessary; new, correct curves have been produced and distributed.

This problem had apparently existed since March 1989, when the curves were generated by evaluation of vendor (Advanced Nuclear Fuels) data through corporate and site nuclear engineering. The Unit was subsequently in MODEs 4 and 5 during a scheduled outage June 10-24, 1989.

The significance of the error and its implications considering the actual June 1989 outage were still under evaluation at the conclusion of the inspection. Further inspection will occur if the matter proves important.

c. <u>Plant Control Room Simulator Evaluation</u>

On October 10 through 12, a special evaluation was conducted utilizing the D.C. Cook Unit 2 control room simulator. A team of NRC personnel - consisting of the Senior Resident Inspector and Resident Inspectors assigned to both D.C. Cook and to Palisades (the backup site) and of the responsible NRC Region III Section Chief and the NRR Licensing Project Manager - performed this evaluation.

The following procedures were exercised on the simulator:

(1) **2 OHP 4021.001.011, "Determination of Critical Conditions Donald C. Cook Nuclear Plant"

(2) **2 OHP 4021.001.002, "Reactor Start-UP"

(3) **2 OHP 4021.001.006, "Power Escalation"

(4) **2 OHP 4022.053.001, "Decreasing or Loss of Condenser Vacuum"

(5) **2 OHP 4022.013.006, "Tripping of Protection Set Bistables"

(6) 02 OHP 4023.E-0, "Reactor Trip or Safety Injection"

(7) 02 OHP 4023.ES-0.1, "Reactor Trip Response"

(8) 02 OHP 4023.E-1, "Loss of Secondary or Reactor Coolant"

(9) 02 OHP 4023.ES-1.1, "SI Termination"

(10) 02 OHP 4023.E-2, "Faulted Steam Generator Isolation"

(11) 02 OHP 4023.ECA-3.1, "SGTR W/Loss of Reactor Coolant - Subcooled Recover Desired"

(12) 02 OHP 4023.FR-S.1, "Response to Nuclear Power Generation/ATWS"

(13) 02 OHP 4023.FR-H.1, "Response to Loss of Secondary Heat Sink"

The team noted that procedure E-0 had been recently revised to eliminate a potential problem with handling a loss-of-coolant accident concurrent with complete loss of auxiliary feedwater. Reordering the "exit" step on failure of auxiliary feedwater, still within the owner's group emergency response procedure guidelines, now assures all the critical verifications contained only in E-0 will be performed before the procedure is exited. This revision resolves a concern NRC had raised in an earlier inspection.

Two potential weaknesses were identified in existing procedures. First, procedure FR-S.1 on ATWS did not contain an early instruction to close the main steam stop valves as an aid to conserving steam generator inventory. Consequently, substantial inventory was (perhaps unnecessarily) lost. Second, procedure FR-H.1 on loss of secondary heat sink had no early instruction (concurrent with commencement of pressurizer "feed and bleed") regarding installation of "jumpers" on phase A isolation functions. Phase A is an inevitable result of "feed and bleed" and results in loss of the "bleed" function via isolation of operating air to the pressurizer power operated relief valve. It seemed the procedure could and should prevent this, rather than respond to it after it occurs.

The above potential procedure weaknesses were conveyed to the procedure group responsible for emergency operating procedures for their consideration and appropriate corrective action.

During one scenario involving complete failure/loss of the condensate storage tank (CST) the simulator instructors indicated auxiliary feedwater alignment to its alternate supply (essential service water) should not include opening the supply valves. Since these are not automatic valves, they would have to be opened by operator action from the control room in case of some additional emergency requiring auxiliary feedwater. The inspectors questioned the implicit position that closed the valves; non-automatic valves can make for an OPERABLE flowpath, and were concerned that plant operator training includes this implication.

Other instruction concerns related to the use of non-EOP criteria as a basis for rendering (unneeded) emergency equipment inoperable during an emergency. Examples were: shutdown of an unloaded emergency diesel rather than letting it idle unloaded for more than five minutes (an operating/surveillance guideline) and; placing a recirculating LPSI pump in "pull-to-lock" so that pump/water temperatures would not gradually build up. Neither action seemed critical to equipment protection, so securing and defeating automatic emergency response functions seemed unnecessary, perhaps even ill-advised.

The above instruction concerns were conveyed to and discussed with appropriate licensee staff for their consideration and, if appropriate, corrective action.

Overall, the inspection team found the procedures effective. They were generally clear and straightforward enough to permit successful implementation by knowledgeable (but not specifically Cook-trained) individuals. The symptom-based Functional Restoration Guides were similarly exercised in part (02-OHP 4023.F-0.1 through F-0.6) with no significant deficiencies noted.

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

10. <u>Reportable Events (92700, 92720)</u>

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. <u>(Closed) Licensee Event Report LER 315/87007</u>: missed event-initiated surveillance (sump effluent radiological sampling) due to unrecognized disabling of automatic sampler. An incomplete instrument calibration activity disabled the turbine sump automatic sample compositer (by simulating a no-flow signal) when the test equipment was left connected at the end of the work day. Sump discharges were very intermittent, so the lack of sample accumulation in the compositer receiver was not readily apparent. When the problem was recognized the next day, an approximate 16-hour interval had elapsed, which exceeded the eight hours specified for alternate manual sampling and analysis.

To prevent recurrence, instrument group supervisors and work planners were informed of the affect of the activity, and the recorder being calibrated was labeled with a sign warning of its connection with the compositer.

Radiation monitors on lines upstream of the sump were checked; all were operable and showed no unusual radioactivity over the period in question.

b. (Closed) Licensee Event Report LER 315/89003: Unit 1 reactor trip on March 18, 1989, while shutting down. The unit tripped from about 10 percent power when the high flux trip signal from intermediate range nuclear instrument channel N-35 auto-unblocked before it cleared and reset. The reset should occur first, normally at around 12.5 percent. This is because reset is nominally calibrated to an electric current equal to half the trip setpoint current (at or below 25 percent). In this case, the trip setpoint was conservatively set due to rounding down calculated current values, then the reset setpoint (half the trip setpoint) was also rounded down to the next whole number. The combined conservatisms resulted in the reset setpoint being below 10 percent nuclear power on one channel. When the block cleared at 10 percent, the trip followed immediately.

To prevent recurrence, procedures were changed to ensure the reset setpoint, while still conservative, will be set above the auto-unblock setpoint. An inspection of like instrument channels in Unit 2 disclosed one with the same type overlap problem, which was corrected.

The plant responded normally upon trip actuation, with no system or equipment problems noted.

c. (Closed) Licensee Event Report LER 315/89004: containment isolation valve Type C test results disclosed leakage above $0.60L_a$. The original LER was submitted with some testing and followup actions still incomplete. LER Supplement 1 dated August 31, 1989, included complete information on test results. Further, as discussed in Inspection Report No. 50-315/89018(DRP); No. 50-316/89018(DRP) (Paragraph the Supplement includes a discussion of the circumstances surrounding a repair to valves ICM-250 and ICM-251 which were performed without first obtaining "as-found" leak rates. The repair to valves ICM-250 and -251 was to replace stem packing. The valve internals were not repaired. Based on very low as-left seat leakage (which should closely approximate as-found in the absence of internal maintenance) these valves would not have added significantly to the as-found total.

The final total leak rate (maximum pathway method) was $3.08L_a$, primarily due to just three valves. All three valves were each in line with other valves having very low leak rates. All three were repaired or replaced. None had a significant failure history among six previous cases of Type C test results totaling above $0.60L_a$ for Unit 1.

Determining as-found leakage to be above $0.60L_a$ is not a violation of regulatory requirements in the subject case, because the significant contributors appeared to result from random component degradation. Failure to determine as-found leakage prior to performing maintenance, however, is contrary to licensee procedures and, by reference through Regulatory Guide 1.33 Appendix A, is contrary to Technical Specifications. Further, such actions are contrary to 10CFR50 Appendix J as applied to this valve design.

The violation was identified, reported and corrected by the licensee. It resulted from personnel error by maintenance personnel, who failed to follow procedure controls correctly. The procedures properly cautioned that leak testing must precede maintenance because of a similar occurrence some 2 1/2 years earlier, when such precautions did not exist. Given the amount of time elapsed between the events, the 1989 problem is not considered repetitive or programmatic. Further, it lacks safety significance because the work was external to the valve seats and would not have affected the leak rate materially.

d. <u>(Closed) Licensee Event Report LER 315/89005</u>: inoperable containment isolation valve for component cooling water (CCW) system. Valve 1-CCM-458 (CCW supply to reactor coolant pump coolers) failed to close during testing on March 30, 1989. The unit was in a refueling shutdown at the time, so there was no immediate significance to the failure. Internal damage was found in the valve operator upon disassembly. An "interim" LER was submitted when the root cause and safety evaluations were not able to be completed within 30 days. The estimated submission date for the final LER was June 9, 1989. On that date, the licensee submitted a letter withdrawing the LER, because the event was determined not to be subject to mandatory reporting requirements, and not to be a safety hazard or an unreviewed safety question.

e. <u>(Closed) Licensee Event Report LER 315/89006</u>: ECCS flow balance out-of-specification. Routine mandatory flow balance testing, conducted during the 1989 refueling outage as per Technical Specification 4.5.2, found total safety injection flow from the North SI pump to be slightly in excess (644 gpm vs. 640 gpm) of the allowable upper limit. Adjustments were made to system flow control valves to restore the flow within the specified range. The deviation apparently resulted from small normal system fluctuations combined with instrument uncertainties. An evaluation of the magnitude of the discrepancy showed it was not safety significant. In fact, the licensee concluded the currently prescribed acceptance range for SI flow is much more restrictive than necessary to meet safety requirements with comfortable margins. A broadening of the acceptance range has been requested and is under evaluation by NRC.

f. <u>(Closed) Licensee Event Report LER 315/89008</u>: deficient monthly calibration checks. This condition applied to both D.C. Cook units. A generic Westinghouse letter dated December 1, 1988 and entitled "Calibration of AFD Instrumentation" addressed how various aspects of excore-indicated axial flux difference (AFD) should be compared as part of monthly surveillance. One such aspect involves comparing the excore-indicated value to the value input to the F (Delta I) penalty function generator. A review of licensee procedures

against the Westinghouse clarification found this particular comparison involving the penalty function generator was being done as part of routine quarterly testing rather than monthly.

The described comparison was transferred to a monthly test procedure. The reason for the original choice of quarterly vs. monthly could not be determined. A review of historic data found the input to the penalty generator had been quite stable, requiring only infrequent (and minor) adjustment. Omission of two thirds of the comparisons had therefore not constituted a significant safety hazard.

The licensee's omission of the described testing was, however, a violation of Technical Specification requirements at 3.3.1.1 to perform testing stipulated in Table 4.3-1. The inspector took specific note, in reviewing this matter, of the fact that five "Previous Similar Events" are listed in this LER. A further review determined the "similarity" to involve the fact that instrument surveillance procedures, to accomplish testing governed by Technical Specification Tables, contained discrepancies such that complete literal compliance with the Specification was not achieved. Three of the five previous "similar" events, in fact, occurred in close chronology during 1986; special licensee reviews for this purpose were conducted to address a generic concern about the technical quality of instrument test procedures to implement "Table" requirements. A variety of causes, a variety of instruments, and a variety of discrepancy types (scope, frequency, technical consistency) were involved in these events. LER 315/89008 did not involve the same instruments, the same root cause or consequences, or the same technical nature as these previous events, so it was determined not to demonstrate a repetitive problem.

g. <u>(Closed) Licensee Event Report 315/89012</u>: ECCS components simultaneously inoperable in both trains. With the "A" Train safety injection pump inoperable for ongoing maintenance, a surveillance test was authorized and performed on "B" Train rendering it (including the associated safety injection pump) simultaneously inoperable. The test authorization resulted from errors on the part of the Shift and Unit Supervisors (both Senior Reactor Operator licensed) who did not recognize the unacceptability of the specific test in the existing circumstances. The test procedure was deficient in not highlighting the need to assure all opposite-train equipment was OPERABLE. Also, the maintenance scheduling process did not specifically coordinate with the testing schedule; the test occurred second, but it was scheduled first.

Though not addressed explicitly in the LER, simultaneous inoperability of equipment in both ECCS trains placed the unit in Technical Specification 3.0.3. This Specification requires initiation of action within one hour to place the unit in an acceptable condition. Because the dual inoperability was not recognized, no such action was initiated. Instead, one train was routinely restored to OPERABLE status upon test completion, which occurred after 68 minutes.

Failure to comply with an "action" requirement of Technical Specification 3.0.3 is considered a violation of the Specification (Violation 315/89029-01).

A violation of a Technical Specification "action" requirement is a potentially significant enforcement matter. An NRC Enforcement Board was convened on October 25, 1989, to consider this event. The Board concluded that this specific example lacked any substantial safety significance, and it was adjudged to be a Level IV violation. In consideration of the causes of the event, however, along with the occurrence of a somewhat similar event a few weeks earlier (ref. Inspection Report 50-315/89026(DRP); 50-316/89026(DRP) Paragraph 3.6) the Board recommended a Management Meeting be scheduled between NRC and licensee representatives to discuss these and other timely matters. The Management Meeting is addressed further in Paragraph 14. below.

h. <u>(Open) Licensee Event Report LER 316/88003</u>: RPS instrument <u>tolerances repeatedly violated.</u> The original LER has been supplemented four times, most recently on September 11, 1989. The licensee has concluded the observed instrument "drift" has remained within safe limits, although outside current Technical Specification tolerances, and that no more stable devices are currently available as replacements. Thus, a request to relax the Technical Specification tolerances was submitted on November 29, 1988. A technical review of this LER was conducted within NRC Region III which derived several questions concerning matters not explicitly stated in the LER. The inspector relayed these questions to the licensee and plans to review this matter further upon receipt of the requested additional information.

i. <u>(Closed) Licensee Event Report LER 316/88009</u>: containment integrity <u>requirements during core alterations not met.</u> This report describes conditions applicable to both D.C. Cook units. At D.C. Cook, lower containment atmospheric radiation is sampled (essentially continuously) for iodine and particulate concentrations by drawing a sample out of containment through particulate filters and iodine cartridges. The filters and cartridges require regular change out. While they are being changed, an open pathway can exist from the containment atmosphere to the auxiliary building, unless the sample inlet line is isolated. Such an open pathway is not permissible during reactor core alteration (i.e. fuel handling) yet the changeout procedure did not require isolating the pathway for a changeout made during such periods. Such events (open pathway while handling fuel) have almost certainly occurred repeatedly, each lasting up to a few minutes, during the past history of the two units. A requirement of each unit's Technical Specifications, to suspend core alterations if integrity is not maintained, has thus very likely been repeatedly violated. Applicable procedures were revised to prevent a recurrence.

j. <u>(Closed) Licensee Event Report LER 316/88010</u>: containment purge in <u>service with inoperable control room radiation</u> alarm annunciation. The subject alarm annunciation is required by Technical

Specifications whenever the purge is in service. In the subject event, the reactor and containment were both completely void of nuclear fuel (during a prolonged outage to replace the steam generators) and purge was in service. Due to a misunderstanding of language in an administrative guideline, the radiation monitoring system control terminal was then removed from service for a design change. The individual authorizing this action (licensed SRO) understood the guideline to indicate the Specification could be satisfied by recording local readings, which is incorrect. The error was recognized and corrected about 12 hours later, and the guideline was clarified to prevent a recurrence. Radiation monitor system safety functions (to isolate purge on high radiation) were always OPERABLE.

k. <u>(Closed) Licensee Event Report LER 316/88011</u>: unexpected actuation of engineered safety feature (Phase B Isolation) during testing. A new circuit time-response test was being conducted with the unit shutdown and defueled. Part of the test utilized logic test switches on the SSPS test panel to initiate main steam isolation valve closure. This was the only actuation expected. When the switch was used, however, containment isolation Phase B also actuated. A subsequent review of the details of the test circuit showed this should have been expected; the circuit worked as designed.

Post actuation response of all in-service Phase B equipment was correct. To prevent recurrence, the test procedure was revised to incorporate the subject portion into another section which intentionally verifies the Phase B time response, and an alternate means was developed for actuating steam isolation valve circuits only.

l. <u>(Closed) Licensee Event Report LER 316/89003</u>: reactor vessel level indication system (RVLIS) calibration shift due to air leakage into capillary tubing during mid-cycle outages. This problem was discovered during a refueling outage when a routine required calibration was performed. Evidence suggested the system had become inaccurate during some previous mid-cycle outage, when the reactor was depressurized so that air could leak into the tubing. The design accuracy specification of plus/minus one-percent was exceeded by all three transmitters on both trains, with a worst case of "drift" in excess of 40 percent on one "A" Train transmitter. The precise time the problem developed could not be identified.

The system was made leak-tight by seal-welding the steel dust cap over the high-point fill valve stem and seal. The transmitters were then recalibrated and restored to OPERABLE for unit operation.

An evaluation of the significance of the operators receiving erroneous level indication was conducted. The only likely incorrect action identified was to vent the reactor vessel post-accident to remove voids and increase indicated vessel level. This would result in decreased indicated level, however, and the RVLIS error would become evident.

Since it is likely the RVLIS was out-of-calibration during periods of required system operability, the effective Technical Specification was violated.

m. (Closed) Licensee Event Report LER 316/89012: incomplete monthly channel checks. When Unit 2 Technical Specifications were revised by Amendment No. 95 to add channel check requirements for containment water level instruments, the licensee's implementing procedures were not likewise revised. As a consequence, the specified channel checks were not performed for four months.

The Amendment occurred in late 1987, but did not become effective until a post-refueling unit startup in March 1989. In the meantime, a combination of errors occurred which resulted in the procedures remaining unchanged. First, no departmental action request was initiated due to an oversight. Subsequently, the duplicative corporate action item tracking system item was overlooked, perhaps due in part to an over-reliance on the departmental tracking list.

When the error was discovered in June, 1989, a channel check found all the instruments operable. The governing procedure was revised and the required channel checks have subsequently been routinely performed.

The NRC Enforcement Policy (10 CFR 2 Appendix C) describes condition for which violations of requirements will not normally be subject to a Notice of Violation. These include that the violation be identified, reported (if required) and corrected by the licensee, that it be a Severity Level IV or V (lesser safety significance) and that it be neither repetitive nor otherwise indicative of licensee failure to correct a known problem. Among the items discussed above, Items c, f, i, j, l, and m concern licensee-identified violations which are deemed to meet these criteria and for which no Notice of Violation is being issued.

One violation was identified in this area which will be the subject of a Notice. Six potential violations (not cited) and no deviations, open or unresolved items were noted in this area.

11. NRC Compliance Bulletins, Notices and Generic Letters (92703)

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.

(Open) Generic Letter 88-03: Resolution of Generic Safety Issue 93, Steam Binding of Auxiliary Feedwater Pumps. The inspector reviewed the licensees response to GL 88-03 dated May 31, 1988 and the below referenced procedures. The response indicates that the Operations Department is required by Procedure OHP 4030.001.001 "Routine Plant Inspection Outside of Control Room" to perform a shiftly (every 8 hours) check on the auxiliary feedwater (AFW) lines to verify the AFW line temperature is ambient. Review of this procedure by the inspector identified that the above checks were not requirements but were guidelines. The guidelines to perform the checks are part of the procedure in Attachments No. 1 and No. 2. The procedure states "Although these do not represent specific requirements, be aware that the operator should develop a habit or pattern to routinely check those items on the guidelines." When this was communicated to the licensee they agreed to modify the procedure to make the AFW line temperature checks a requirement. In addition, Procedures OHP 4021.056.002 "Operation of the Auxiliary Feed Pumps During Plant Startup and Shutdown", and surveillance test Procedures OHP 4030.STP.017T and OHP 4030.STP.017R for the turbine driven and motor driven auxiliary feedwater pumps require checking the AFW line temperature 30 minutes and 90 minutes after stopping an AFW pump. Procedure OHP 4022.056.001 "Steam Binding in Auxiliary Feed Pumps" provides guidance for recognizing steam binding and for restoring the AFW pump to operable status if steam binding were to occur.

The May 31, 1988 response also committed to reference the Generic Letter in the above procedures in the next biennial review to assure that procedures will be maintained. Review of how the licensee implements changes to procedures because of commitments disclosed some weaknesses in their system. Procedures 1-OHP 4030.STP.017T and 1-OHP 4030.STP.017R were revised for their biennial review on June 10, 1988 and June 30, 1988 and neither included the reference to GL 88-03. These were realatively close to the May 31, 1988 commitment date and it can be understood how the reference would not be included. However, Procedure 1-OHP 4021.056.002 was issued as Revision 9, incorporating biennial review, on February 21, 1989, eight and one half months after the commitment date and did not include the reference to GL 88-03. It was found the the licensee took six months to place the change letter for each of the procedures in the file so it would be reviewed during the next biennial review. This change letter was dated November 30, 1988 and was put in the file after the biennial review for the above Procedure (1-OHP 4021.056.002) was started. It appears that once a biennial review is started the change file is not reviewed during the revision process even if that process takes three months.

The fact that the reference to Generic Letter 88-03 was not included in the above procedures in a timely manner and that AFW line temperature checks were guidelines instead of requirements may have contributed to the licensee's inability to recognize the lack of tour performance in the Auxiliary Feed Pump Rooms by the auxiliary equipment operator (AEO) (see Paragraph 3.b). Additionally, the AEO did not check the AFP discharge lines to see if they were at ambient room temperature. Thus, the licensee did not fully meet their commitment as defined in their May 31, 1988 response to Generic Letter 88-03. This item will remain open pending additional NRC investigation of the auxiliary operators performance with regard to fulfilling the above commitments.

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

12. Allegations (92705)

(Closed) Allegation (AMS No. RIII-89-A-0075): An anonymous allegation was received in the NRC resident office on May 28, 1989. It alleged that a current trend at the station is to assign junior Radiation Protection Technicians (RPTs) to job coverage for work formerly done by experienced RPTs, and that the junior RPTs do not perform as well as senior RPTs in that they give no direction or recommendations regarding minimization of contamination and radiation exposure. The alleger referred to current work on the reactor head and cited an instance where a junior technician was in the wrong place when two contaminations and a 150 mr exposure occurred.

In review of the allegation, the inspector contacted the Radiation Protection Manager (RPM), a plant health physicist, the contractor site manager and training coordinator, four licensee RPTs, three of whom were previously contractor RPTs during previous refueling outages, and two mechanical maintainance workers with combined experience of about 24 years at the station. The inspector also reviewed radiation protection training and personnel qualification records, and radiation protection logs. The inspector's review focused on work performed by junior technicians currently and during the previous outage.

Discussion:

The current station (house and contractor) RPT staff consists of about 60 senior and 17 junior technicians. During the two outages which overlapped in winter/spring 1989, the total number of RPTs consisted of about 110 seniors and 65 juniors compared to about 80 seniors and 15 juniors used during the spring 1988 refueling outage. According to the licensee, the increase in the ratio of juniors to seniors was due to contract senior manpower shortages in early 1989. It is licensee practice that junior RPTs perform all radiation protection functions under the direction of a senior RPT and/or a Job Coverage Coordinator (JCC). According to the RPTs interviewed these functions included performing direct and indirect pre-job and routine surveys, counting air samples and smears, personal and material control at control access points, personnel frisking, providing guidance in removal of protective clothing, and general assistance to a senior RPT or JCC. The licensee allows direct job coverage of RWP work to be performed by junior RPTs only under controlled conditions. Only one of the RPTs interviewed indicated performance of senior RPT work while a junior RPT. This was stated to have been performed under controlled conditions during the last outage. All of the RPTs interviewed stated that as junior RPTs it was not their function to make recommendations/suggestions concerning radiological controls unless authorized. They stated that during outage activities the junior RPTs did control access points to check personal dosimetry, perform frisks if necessary, and provide guidance in minimizing personal exposure and contamination. However, questions

involving workers SRD readings or existing radiological conditions in a work area were normally directed to a senior RPT or JCC. Neither of the maintanance workers recalled seeing any instances where junior RPTs were performing senior jobs, nor could they recall other workers expressing concern about this matter.

With regard to the alleged event involving anonymous individuals with personal contamination, and an SRD reading of 150 MR, occurring when a junior RPT was at a control point to provide assistance, the inspector was unable to identify any such occurrences.

The inspector reviewed training lesson plans, training and test records and personnel qualification check sheets for the RPTs interviewed. The record showed that the junior RPTs received formal training by the licensee: General Employee Training (GET) and RCT Training. Contract junior RCTs receive GET and Procedure training, and additional training by the contractor. Based on this review and discussions with the contractor training coordinator it appears the training is sufficient and commensurate with junior RPTs assigned duties.

The allegation was not substantiated. Although it appeared there were more junior RPTs used in 1989 compared to the previous year, the inspector could not find any evidence to indicate there was a trend to assign junior RPTs to jobs formerly assigned to senior RPTs, nor could he establish that junior RCTs did not have the qualifications to perform their assigned duties. Also, the inspector could not determine if one of the junior RPTs was in the wrong place when two contamination events and a 150 mr reading occurred on a worker's SRD.

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

13. Region III Requests (92705)

Based on a report from another licensee with a similar design to D.C. Cook plant, that the FSAR was incorrect in stating steam generator blowdown would isolate on initiation of auxiliary feedwater, the inspector was requested to determine how steam generator blowdown would be handled in conjunction with auxiliary feedwater initiation at D.C. Cook.

By review of design documentation and discussions with plant personnel, the inspector determined that manual initiation of auxiliary feedwater does not affect steam generator blowdown. All automatic auxiliary feedwater initiations, on the other hand, are accompanied by steam generator blowdown isolation. This is because the auto-start logic processes the start signals (steam generator lo-lo level, main feed trip loss of load, SIS) via the "feedwater conservation circuit." This circuit has a separate output to isolate blowdown.

FSAR Figure 7.2-1 does not detail the above logic, but neither does it incorrectly claim a blowdown isolation which does not exist.

The above information was conveyed to the requesting party in NRC Region III.

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

14. Management Meeting (30702)

A Management Meeting (attended as indicated in Paragraph 1.b above) was conducted on November 16, 1989, for the purpose of discussing recent operating events and plant management/staff changes. The licensee provided information and assessments regarding the concerns raised by the NRC staff and was responsive to associated questions. The focus of the meeting was generally on plant status knowledge and control of plant activities and configuration. Failures to exercise adequate control, as exemplified by the violation identified in this report (Paragraph 10.g) were specifically discussed.

15. Licensed Operator Training Meeting

An NRC concern was raised due to a high failure rate during the conduct of operator licensing simulator examinations at D.C. Cook. A follow-up NRC inspection was also conducted to help clarify the root cause for the high simulator failure rate in July. The inspection results indicated that the training program exhibited some possible weaknesses that collectively contributed to the failures. These included weakness in the program evaluation methods, inconsistency with the NRC exam method, weakness in the SRO control board training and ineffective program feedback mechanisms.

In response to the NRC concerns and findings the licensee agreed with the basic issues but took exception to the numbers and types of malfunctions and events used in NRC simulator exams as being inappropriate and unrealistic or of low probability.

The region responded to the licensee concerns by inviting facility training representatives to the region to discuss exam strategy. During the meeting held on November 16, 1989, members of the region staff and the facility training staff exchanged viewpoints and methods for establishing simulator event sequences. At the conclusion the facility representatives and region staff had reached a clearer understanding of each others expectations.

16. Management Interview (30703)

The inspectors met with licensee representatives (denoted in Paragraph 1.a) on November 17, 1989, to discuss the scope and findings of the inspection as described in these Details. In addition, the inspector 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. the licensee-identified violation of auxiliary operator shift tour procedures (Paragraph 3.b);

b. the potentially significant discovery of erroneous setpoints for Unit 2 turbine-driven auxiliary feedwater flow retention actuation (Paragraph 6.f);

c. various observations involving emergency procedures and training which arose from utilization/evaluation of the control room simulator (Paragraph 9.c); and,

d. the licensee-identified violation involving concurrent inoperability of elements of both independent safety trains (Paragraph 10.g) and the associated Management Meeting (Paragraph 14).