U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-331/94002(DRP)

Docket No. 50-331 License No. DPR-49

Licensee: Iowa Electric Light and Power
Company
IE Towers, P. O. Box 351
Cedar Rapids, IA 52406

Facility Name: Duane Arnold Energy Center

Inspection At: Palo, Iowa

Inspection Conducted: January 7 through February 7, 1994

Inspectors: J. Hopkins
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Approved: T. Tongue
for R. D. Lanksbury, Chief
Reactor Projects Section 3B

MARCH 4, 1994
Date

Inspection Summary

Inspection on January 7 through February 7, 1994
(Report No. 50-331/94002(DRP))

Areas Inspected: Routine, unannounced inspection by the resident and regional inspectors of event followup, operational safety, maintenance, surveillance, plant trips, and report review.

Results: An executive summary follows:

EXECUTIVE SUMMARY

Plant Operations

The plant operated up to full power during the period with minor down power operations due to surveillance testing. The control room operators promptly identified the failure of the average power range monitor (APRM) (Section 2.b). Good team work and communications, both inside and outside of the control room, were observed between the control room operators and maintenance technicians during the high pressure coolant injection (HPCI) system surveillance (Section 5.d). Further dialogue between the NRC and the licensee was needed concerning an interpretation that a missed surveillance did not specifically require equipment to be declared inoperable (Section 5.a).

Maintenance

Failure to incorporate a vendor required test of the flow referenced APRM scram trip setpoint resulted in a violation (Section 5.a). Inadequate planning and review of maintenance for the offgas ventilation system and authorizing the removal of a danger tag prior to completing an operability test resulted in two non-cited violations for failure to follow procedures (Sections 2.a and 2.c). These errors represented a departure from the licensee's routine performance. The inspectors were concerned that senior operations personnel were directly involved in the errors. Good coordination between the engineering, operations, and maintenance departments was noted during the HPCI system surveillance (Section 5.d).

Engineering

The inspectors were concerned that the performance trending data had not predicted the failures of the "C" residual heat removal (RHR) pump (Section 4) and the Barksdale pressure switches (Section 5.b). There appeared to be a lack of consistent, and questioning attitude by the engineering and maintenance departments during the troubleshooting of the "C" RHR pump and the Barksdale pressure switches. These examples were not indicative of the licensee's routine performance. A questioning attitude was noted during the troubleshooting for the "A" RHR pump. An inspection followup item was identified concerning the adequacy of the electrolytic capacitor shelf-life program (Section 2.b). The inspectors will continue to evaluate the licensee's actions to improve the quality of materials received from GE (Section 2.b).

Plant Support

No concerns were identified with housekeeping, cleanliness, and radiological control practices during the report period.

DETAILS

1. Persons Contacted

J. Franz, Vice President Nuclear
*D. Wilson, Plant Superintendent, Nuclear
*R. Anderson, Operations Supervisor
*P. Bessette, Supervisor, Regulatory Communications
*J. Bjorseth, Maintenance Superintendent
*J. Kinsey, Licensing Supervisor
J. Kozman, Supervisor, Configuration Control Engineering
*M. McDermott, Manager, Engineering
*K. Peveler, Manager, Corporate Quality Assurance
J. Thorsteinson, Assistant Plant Superintendent, Operations Support
*G. Van Middlesworth, Assistant Plant Superintendent, Operations and Maintenance
*K. Young, Manager, Nuclear Licensing

In addition, the inspectors interviewed other licensee personnel including operations shift supervisors, control room operators, engineering personnel, and contractor personnel (representing the licensee).

*Denotes those present at the exit interview on February 7, 1994.

2. Followup of Events (93702)

During the inspection period, the licensee experienced several events, some of which required prompt notification of the NRC pursuant to 10 CFR 50.72. The inspectors pursued the events onsite with licensee and/or other NRC officials. In each case, the inspectors verified that the notification was correct and timely, if appropriate, that the licensee was taking prompt and appropriate actions, that activities were conducted within regulatory requirements, and that corrective actions would prevent future recurrence. The specific events are as follows:

January 7, 1994 - Missed average power range monitor (APRM) surveillance. (See Section 5.a for details.)

January 12, 1994 - Three of four reactor core isolation cooling (RCIC) steam line pressure switches failed surveillance. (See Section 5.b for details.)

January 17, 1994 - Offgas treatment system process flow line blocked with ice.

January 19, 1994 - Both offgas ventilation stack radiation monitors out of service.

January 20, 1994 - Local power range monitor Group A power supply failure.

February 1, 1994 - Inoperable containment isolation valves returned to service.

a. <u>Both Offgas Ventilation Stack Radiation Monitors Out of Service.</u>

On January 19, 1994, at approximately 2:35 a.m. (CST), with the plant operating at approximately 100 percent power, both offgas ventilation stack radiation monitors were taken out of service to support maintenance activities on a sample line drain trap. Technical specifications (TS) required that secondary containment integrity be established with the standby gas treatment (SBGT) system in operation within 1 hour. The two radiation monitors were returned to service, following maintenance, at approximately 2:14 p.m. on January 19. The radiation monitors were out of service for approximately 11 hours and 39 minutes without secondary containment being established with the SBGT system in operation. The discrepancy was identified by the operations shift supervisor (OSS) during his review of logs on January 24. The licensee notified the NRC in accordance with 10 CFR 50.72 in that this event could have prevented a system needed to control the release of radioactive material from performing its safety function. A second offgas ventilation stack radiation monitor system, which performed the same function, was in operation during the event. There were no unplanned or unmonitored radioactive releases.

The licensee's preliminary root cause evaluation identified inadequate maintenance planning due to personnel error. Nuclear Generation Division (NGD) procedure, 1408.1, "Maintenance Action Request (MAR)," required that applicable TSs be referenced when maintenance activities were being planned. Procedure 1408.1 delegated that responsibility to the Planner OSS, a licensed senior reactor operator. Additionally, procedure NGD 1408.1 required, in part, that the onshift OSS review the MAR to ensure it was complete and correct, and that all pre-maintenance requirements (such as TS) were completed prior to releasing the MAR for work. Based on interviews, the Planning OSS indicated that he was not aware that the offgas ventilation stack radiation monitors were TS related equipment. He also started that he had not reviewed TS when the maintenance activities were planned. The Planning OSS used the guidance found in annunciator response procedure (ARP) 1C03A-C-4, for a failed offgas ventilation stack radiation monitor, to determine the required compensatory actions for taking both offgas ventilation stack radiation monitors out of service. The offgas stack radiation monitors were incorporated into TS with Amendment 193, dated July 1993. However, the ARP was not updated to reflect the change. This was a contributing factor leading to the TS violation.

Two separate MARs associated with the offgas ventilation stack radiation monitors (rerouting a sample return line and repair the drain trap) were reviewed by the same Planning OSS. The lack of

TS required actions in the MAR for rerouting the sample line was identified on January 14 by the onshift OSS, prior to removing either radiation monitor from service. The MAR was revised to reflect the correct TS requirements, and the maintenance was successfully completed. However, the error in the MAR for the sample line drain trap was not identified prior to removing both radiation monitors from service on January 19. The onshift OSS that authorized the release of work indicated that the MAR had not specified any TS requirements and that the pre-maintenance requirements appeared reasonable and had been satisfied.

The licensee's immediate corrective actions to prevent recurrence included: (1) revision of the failed radiation monitor ARP to reflect the current TS requirements; (2) evaluation and revision, as needed, of other ARPs, STPs, and procedures that could have been affected by TS Amendment 193; (3) reviewing existing TS instrument MARs to ensure that the appropriate TS action statement was referenced; and (4) training on this event with operations department personnel and maintenance planners to stress the importance of reviewing TS requirements. Additionally, licensee management reviewed the event with each of the operating crews and the supervisors to re-emphasize the need for attention to detail. Long term planned corrective actions included training all personnel involved in the planning and conduct of maintenance on this event, modifying the plant equipment data base to aid maintenance planners in determining the appropriate TS requirements for equipment taken out of service, and performing a root cause analysis using the Human Performance Enhancement System review. Additionally, the licensee planned to compare these issues to previously identified human performance concerns to determine if there were any generic implications (See inspection report (IR) 93015). The proposed corrective actions reviewed by the inspectors appeared adequate to prevent recurrence.

Technical specification 6.8.1 specified that written procedures be implemented covering areas of corrective maintenance actions which could have an effect on nuclear safety. Procedure 1408.1 required: (1) that applicable TSs be referenced when maintenance activities were being planned, and (2) that the onshift OSS review the MAR to ensure it was complete and correct, and that all pre-maintenance requirements (such as TS) were completed prior to releasing the MAR for work. Failure to identify the TS requirement during the MAR planning process, and failure to ensure that the appropriate TS requirements were met prior to releasing the MAR for work, was a violation of TS 6.8.1. This violation was not cited because the licensee's efforts in identifying and correcting the violation met the criteria specified in Section VII.B of the "General Statement of Policy and Procedure for NRC Enforcement Actions" (Enforcement Policy, 10 CFR Part 2, Appendix C).

Section 2.c below addresses additional concerns with personnel errors.

b. Local Power Range Monitor (LPRM) Group A Power Supply Failure.

On January 20, 1994, with the plant operating at approximately 100 percent power, the positive 20 Vdc power supply for LPRM Group A failed. This resulted in the loss of input signals from 9 of the 19 LPRMs that fed APRM Channel F. The output signal of APRM Channel F provided control room indication and reactor protection system (RPS) signals. The output of the APRM Channel F indicated approximately 23 percent reactor power following the failure. The APRM channel was bypassed, the power supply replaced and calibrated, and on January 21 APRM Channel F was returned to service.

The inspectors were concerned that the failed power supply had not generated a "half scram" signal; and that the only indications of the inoperable APRM channel were the strip chart recorder on the main control panel, the APRM Channel F local indication in the control room "back panels", and the process plant computer. The control room operators promptly identified the APRM Channel F failure from the indications on the plant process computer. Even with nine LPRM inputs to APRM Channel F failed, no alarms or warning lights actuated; and APRM Channel F still appeared to be operable. Thirteen LPRM inputs, with at least two inputs from each level, were required for APRM Channel F to be operable. The Duane Arnold Energy Center (DAEC) and General Electric (GE) performed an engineering evaluation of the circuit design to determine if the LPRM and APRM circuits had operated as designed, and if the circuit design was adequate. General Electric and DAEC concluded that the circuits had operated as designed, and that this type of failure was only possible at plants with a "shared LPRM" system design. A "shared LPRM" system design used common LPRM inputs for two diffident APRM channels.

According to GE, the APRM system was designed to monitor reactor power by the LPRM signals, but not to determine if the LPRM signals were valid. The LPRM and APRM systems were not designed to automatically produce an alarm for all failures. Most failures required operator intervention to recognize and bypass the failed LPRM and APRM channels. A failure of the positive 20 Vdc power supply on APRM channels A through F would have generated a "half scram" signal and the associated alarms. Since LPRM Group A was not designed to provide RPS signals, there was no alarm to indicate the failure of its 20 Vdc power supply. General Electric described this as a design deficiency of the "shared LPRM" system. However, GE stated the risk to plant safety was small because the failure was readily detectable by control room operators.

The failed power supply was the result of two failed transistors and one failed aluminum electrolytic capacitor. The licensee was unable to determine the exact failure mechanism of the individual components. The licensee identified that there was no shelf-life restrictions on the power supply stored in the warehouse. The inspectors reviewed GE service information letter (SIL) 290, "Aluminum Electrolytic Capacitor Aging," dated February 1979, and determined that the licensee had not implemented the recommendations of the SIL to spot check instruments with aluminum electrolytic capacitors taken out of service for maintenance or on spare instrumentation taken out of storage to be placed in service. However, the licensee was testing individual aluminum electrolytic capacitors that were stored, prior to use and "bench tested" instrumentation prior to installation. A program to implement the recommendations of SIL 290 was initiated in March 1993 as part of the licensee's scram reduction program. However, the program had not been fully developed or implemented. The adequacy of the licensee's electrolytic capacitor shelf-life program and their implementation of GE SIL 290 will be tracked as an inspection followup item (IFI) 331/94002-01(DRP).

The spare power supply from the warehouse had a fault in both the positive and negative 20 Vdc power supplies. It was repaired prior to installation. The power supply had been refurbished by GE in 1986 and had not been used since it was returned to DAEC. The licensee and GE were evaluating the root cause of GE returning a faulty power supply. This example, coupled with the improperly bent locking washer for the top motor shaft nut of the "C" residual heat removal (RHR) pump (See section 4.a below) and the cracked collar on the handle of the a replacement reactor mode selector switch, caused the inspectors' concern with the quality of materials returned by GE. The inspectors will continue to evaluate the licensee's actions to improve the quality of materials received from GE.

c. <u>Inoperable Containment Isolation Valves Returned to Service.</u>

On January 31, 1994, with the plant operating at approximately 100 percent power, the "B" channel of the containment atmosphere monitor (CAM) system was taken out of service for maintenance on three solenoid valves in the torus sample return line. Two of the valves, SV-8109B and SV-8110B, were automatic valves associated with the primary containment isolation system (PCIS). On February 1, the PCIS valves were returned to service and the manual containment isolation valve, V-81-0068, was reopened prior to performing the required operability test on the PCIS valves. On February 2, the onshift OSS identified the error during his review for the operability test. The manual containment isolation valve was shut, and the licensee notified the NRC, in accordance with 10 CFR 50.72, that this event could have prevented a system needed to mitigate the consequences of an accident from performing its safety function. The test was satisfactorily completed; and on February 2, the "B" channel of the CAM system was declared operable.

The licensee reviewed the event and determined that the containment isolation function of the PCIS valves was not affected by the maintenance. Therefore, no post-maintenance operability test for containment isolation was required to comply with TS. The inspectors reviewed the licensee's evaluation and had no immediate concerns. The 10 CFR 50.72 notification was retracted on February 4.

The licensee's initial root cause evaluation was identified as personnel error for the PCIS valves being returned to service prior to performing the required operability test. The inspectors were concerned that even though containment integrity was maintained at all times, the danger tag on valve V-81-0068 was removed prior to the completion of the operability test specified on the MAR. Equipment tagout number 940179 specified that valves SV-8109B and SV-8110B (PCIS valves) were to be operable prior to unisolating valve V-81-0068. Based on interviews, the onshift OSS that authorized the removal of the tags indicated that he had been distracted by testing activities on the "A" RHR pump and had not performed a detailed review of the equipment tagging form.

The licensee's immediate corrective actions were to review the event with each of the operating crews and the supervisors in order to re-emphasize the need for attention to detail. Long-term corrective actions included a review of the tagout procedures and practices to determine if revisions or enhancements were needed. Additionally, the licensee planned to compare these issues to previously identified human performance concerns (See IR 93015) to determine if there were any generic implications.

Technical specification 6.8.1 specified that written procedures, covering areas of corrective maintenance actions which could have an effect on nuclear safety, be implemented. Equipment tagout number 940179 specified that valves SV-8109B and SV-8110B (PCIS valves) were to be operable prior to unisolating valve V-81-0068. Failure to declare valves SV-8109B and SV-8110B operable prior to unisolating valve V-81-0068, was a violation of TS 6.8.1. This violation was not cited because the licensee's efforts in identifying and correcting the violation met the criteria specified in Section VII.B of the "General Statement of Policy and Procedure for NRC Enforcement Actions" (Enforcement Policy, 10 CFR Part 2, Appendix C).

The inspectors considered this personnel error and the failure to identify the TS requirement in the offgas ventilation MAR (See section 2.a above.) a departure from the licensee's routine performance. The number and significance of personnel errors since the end of the refueling outage (October 1993). had been very low. The inspectors were concerned that senior operations personnel (OSS) were directly involved in the errors. Continued attention to detail was required from all levels of the operations department to prevent personnel errors. The proposed corrective actions reviewed by the inspectors appeared adequate to prevent recurrence.

Two non-cited violations and no deviations were identified in this area. One IFI was identified.

3. Operational Safety Verification (71707) (71710)

The inspectors observed control room operations, reviewed applicable logs, and conducted discussions with control room operators during the inspection. The inspectors verified the operability of selected emergency systems, reviewed tagout records, and verified proper return to service of affected components. Tours of the reactor building and turbine building were conducted to observe plant equipment conditions, including potential fire hazards, fluid leaks, and excessive vibrations and to verify that maintenance requests had been initiated for equipment in need of maintenance. It was observed that the Plant Superintendent, Assistant Plant Superintendent of Operations, and the Operations Supervisor were well-informed of the overall status of the plant and that they made frequent visits to the control room. The inspectors, by observation and direct interview, verified that the physical security plan was being implemented in accordance with the station security plan.

The inspectors observed plant housekeeping and cleanliness conditions and verified implementation of radiation protection controls. No concerns were identified during the report period. During the inspection, the inspectors walked down the accessible portions of the low pressure coolant injection system to verify operability by comparing system lineup with plant drawings, as-built configuration or present valve lineup lists; observing equipment conditions that could degrade performance; and verifying that instrumentation was properly valved, functioning, and calibrated.

These reviews and observations were conducted to verify that facility operations were in conformance with the requirements established under technical specifications, Title 10 of the *Code of Federal Regulations*, and administrative procedures.

Leak Into Reactor Building Closed Cooling Water (RBCCW) System

On December 18, 1993, with the reactor at approximately 100 percent power, plant operators determined that the level in the RBCCW surge tank was slowly increasing (See IR 93023 for details). Based on the chemistry samples and isolation of individual components cooled by RBCCW, the most probable source of the leak was one of the reactor water cleanup non-regenerative heat exchangers (NRHX). Based on trends of the RBCCW surge tank level and chemistry samples, the leak had apparently stopped at the end of the report period. The licensee's initial assessment was that a long duration outage, such as a refueling outage, was needed to repair or replace the NRHXs. The licensee planned to continue normal plant operations and develop long-term plans to isolate and repair the leak.

No violations or deviations were identified in this area.

4. Monthly Maintenance Observation (62703)

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

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 work; activities were accomplished using approved procedures and were inspected as applicable; functional testing and/or calibrations were performed prior to returning components or systems to service; quality control records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; radiological controls were implemented; and fire prevention controls were implemented.

Work requests were reviewed to determine status of outstanding jobs and to assure that priority was assigned to safety-related equipment maintenance which might affect system performance.

Portions of the following maintenance activities were observed and/or reviewed:

- "C" residual heat removal pump repair
- "B" control rod drive pump oil line repair.
- Scram relay inspections.
- "B" channel of the CAM system.

"C" Residual Heat Removal (RHR) Pump Repair

On December 15, 1993, during the performance of surveillance test procedure (STP) 45A002-Q, "LPCI System Quarterly Operability Tests," the "C" RHR pump failed to meet the STP acceptance criteria of a discharge pressure of 165 psig at 4800 gallons per minute (gpm) flow rate. The STP acceptance criteria was established in order to demonstrate that the TS criteria of 14400 gpm for three pumps against a system pressure of 20 psig could be met. (See IR 93023 for additional details.) The licensee reviewed the bases for the STP acceptance criteria and reduced the acceptance criteria to an interim value of 160 psig. Specialists from Region III reviewed the adequacy of the licensee's evaluation to reduce the STP acceptance criteria setpoint and had no immediate concerns.

A leak from the mechanical seal of the "C" RHR pump was identified during the troubleshooting for the low discharge pressure. The mechanical seal package was replaced, and on January 6, 1994, the "C" RHR pump failed a post-maintenance STP with a pump discharge of 156 psig at 4800 gpm. Maintenance was performed on the pump and motor, and on January 9, the "C" RHR pump was successfully tested with a discharge pressure of 170 psig at 4840 gpm. The pump was declared operable on January 10.

During maintenance activities on the pump, excessive pump and motor shaft endplay (axial motion) in the upper motor thrust bearing was identified. The root cause of the excessive end play was that the locking washer for the top motor shaft nut was not properly bent to prevent motor nut rotation. (The top motor shaft nut maintains the motor and pump impeller axial position and sets the preload on the upper motor thrust bearing.) The licensee concluded that the axial position of the motor and impeller was properly set after the motor was refurbished by GE in 1988. However, the locking washer was not properly bent to prevent rotation of the top motor shaft nut. (See section 2.b for other concerns with the quality of materials received from GE.) The top motor shaft nut gradually "backed off" the upper motor bearing assembly as the motor was started and stopped, and the axial position of the impeller gradually lowered in the pump casing. The excessive shaft endplay increased wear on the impeller and the pump wear ring. The wear increased the clearances between the pump wear ring and impeller which resulted in increased pump internal recirculation flow. This resulted in the degraded performance of the pump. Additionally, as the pump impeller's axial position changed, the preload on the pump's mechanical seal was reduced which led to the seal damage and leakage. The other three RHR pump motors and the two core spray pump motors were checked for improperly bent locking washers on the upper motor thrust bearing and no concerns were identified. The licensee planned to measure the shaft endplay and the axial position of the impeller on the other three RHR pumps and the two core spray pumps.

During the initial troubleshooting, the inspectors identified a concern with the availability of parts and procedures needed to rebuild other pumps operating close to their acceptance limits. The licensee evaluated pumps and components operating close to their acceptable limits and determined that the parts and procedures needed to rebuild the core spray pumps were not available. The parts were being ordered and the procedure was being revised at the end of the report period. Additionally, the licensee was in the process of determining why the parts were not available and the procedures were not current.

During the initial troubleshooting, in mid-December 1993, the licensee, the pump vendor representative (Byron Jackson), and a contract pump specialist from MPR Associates, Incorporated, all reviewed the trending data of the pump's discharge pressure and vibration data, and all concluded that the degradation of performance was relatively minor and that a pump overhaul was not required. However, the trend data from the previous year for the "C" RHR pump appeared to identify slowly degrading performance. Based on the "as found" condition of the pump, the inspectors were concerned that the performance trending data had not predicted the failure and had not been "normalized " to provide more useable information. This same concern was identified for the main steam line and RCIC Barksdale pressure switches failures (See section 5.b below). The licensee reevaluated the trending data for the other safety-related pumps and determined that there were no immediate safety or operational concerns.

Initially, it appeared that the licensee had not critically evaluated the pump's performance trending data and had not aggressively searched for the root cause for the degraded pump performance (the excessive motor endplay). The licensee reviewed the bases for the STP acceptance criteria and concluded that it was too restrictive. The licensee's decision to not disassemble the pump in mid-December 1993 was influenced by: (1) the lack of parts needed to complete the maintenance, (2) the need to avoid making a safety-related pump unavailable when repair parts were not available, and (3) the pump vendor's and MPR contractor's conclusions that the degraded performance was relatively minor and an overhaul was not required. The licensee planned to review the performance trending program to determine if the threshold for taking action was adequate.

This poor initial evaluation, coupled with similar examples of: (1) the failure of the "B" standby diesel generator output circuit breaker to close (See IR 93015), (2) the high current trip of the motor operator for the high pressure coolant injection steam isolation valve (See IR 93015), and (3) the excessive setpoint drift of the Barksdale pressure switches (See section 5.b below), appeared to indicate a lack of consistent, and questioning attitude by the engineering and maintenance departments. These examples were not indicative of the licensee's routine performance. The inspectors will continue to evaluate the licensee's performance trending program for safety-related equipment and their root cause evaluations.

Following completion of maintenance on the "C" RHR pump, the inspectors verified that the system had been returned to service properly.

No violations or deviations were identified in this area.

5. Monthly Surveillance Observation (61726)

The inspectors observed technical specification (TS) required surveillance testing 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 accomplished, that test results conformed with TS and procedure requirements and were reviewed by personnel other than the individual directing the test, and that any deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel.

The inspectors witnessed portions of the following test activities:

STP-42A021-Q - RCIC Steam Supply Pressure Low Functional and Calibration

STP-42C001-Q - Quarterly Functional Test and Calibration of APRMs.

STP-45A002-Q - Low Pressure Coolant Injection (LPCI) System Quarterly Operability Tests.

STP-45D001-Q - HPCI System Quarterly Operability Test.

a. Missed Average Power Range Monitor (APRM) Surveillance Requirement

On January 7, 1994, at approximately 12:30 p.m., the licensee determined that a TS required surveillance for APRMs was not being performed in accordance with TS requirements. The requirement was identified as part of an engineering review comparing TS limiting safety system settings (LSSS), analytical analysis limits, and STP acceptance criteria. The APRM flow biased trip signal setpoint, which was an input to the RPS, had been tested routinely up to 100 percent reactor recirculation flow, but had not been tested above 100 percent rated reactor recirculation flow as described in TS section 2.1.A.1. The test confirmed that the scram trip setpoint was limited to 120 percent of rated reactor power when recirculation flow exceeded 100 percent flow. Upon discovery, the licensee took immediate corrective action to revise STP 42C001-Q and test the flow biased trip above 100 percent rated recirculation flow. All six APRM channels were within the desirable trip range when tested above 100 percent rated recirculation flow.

When the inspectors were notified that the trip function had not been fully tested, they questioned why the licensee was not entering the action statement of TS table 3.1-1, which required the reactor to be in at least the "Startup Mode" within 6 hours. The licensee's bases for not entering the TS Action Statement were: (1) based on NRC staff guidance in Generic Letter (GL) 87-09, a reasonable period of time to determine operability was allowed prior to calling the instrument inoperable; and (2) the DAEC TS did not specifically declare equipment inoperable following a missed surveillance. Further discussions with Region III, the Office of Nuclear Reactor Regulations (NRR), and the licensee determined that GL 87-09 guidance was not applicable to the APRMs since approval for TS changes recommended in the GL had not yet been approved for DAEC; and because the surveillance had not been performed after initial plant startup (February 1974), not just missed. The proper path for compliance with the licensing basis, while preventing plant perturbations with untested equipment, was determined to be a notice of enforcement discretion (NOED). Further dialogue between RIII, NRR, and the licensee was needed concerning DAEC's interpretation that a missed surveillance, beyond the maximum allowable frequency extension, did not specifically require equipment to be declared inoperable.

The licensee was verbally granted an NOED for an 18 hour period, if the surveillance testing of four APRMs needed for operability was not completed prior to 6:30 p.m. on January 7. The testing was complete for APRM channels A, C, B, and F at 6:10 p.m. on January 7, at which time operators exited the 6 hour limiting condition for operation (LCO). Since the testing had been completed prior to 6:30 p.m., the NOED was not used. It should be noted that the licensee would have needed to reduce reactor power to be in the startup mode (approximately 15 percent power) by 6:10 p.m., had the NOED approval not been in place.

Technical specification 2.1.A.1 required, in part, that with the mode switch in Run, the APRM scram trip setpoint shall be a maximum of 120 percent rated power at 100 percent rated recirculation flow or greater. Technical specification 4.1.A.1. required that the APRM flow referenced scram trip setpoint be functionally tested quarterly. Failure to verify that the APRM scram setpoint was a maximum of 120 percent of rated power at 100 percent rated recirculation flow or greater, by performing a quarterly functional test of the APRM flow referenced scram trip setpoint, was a violation of TS 4.1.A.1 (331/94002-02(DRP)). Although the licensee identified the missed surveillance, the corrective actions for ensuring that similar technical manual requirements were incorporated into plant procedures did not appear to be in place at the end of the report period.

The licensee's initial root cause evaluation was a lack of awareness of the requirement to test the flow biased scram setpoint above 100 percent recirculation flow. The GE technical manual, GEK 34701, "Power Range Monitoring System," included steps for performing the APRM initial calibration above 100 percent recirculation flow. The steps were not incorporated during the original writing of the STP. Additionally, the technical manual recommended periodic maintenance requirements for the APRMs that were not fully implemented into the maintenance program. The licensee was evaluating the additional recommended maintenance requirements to determine if modifications to the APRM maintenance program were needed.

The inspectors were concerned that the surveillance, maintenance, and preventative maintenance recommendations in the safety-related vendor technical manuals had not been incorporated into the appropriate plant procedures. The failure to incorporate a vendor required post-maintenance measurement for the 4160 Vac circuit breakers into a plant maintenance procedure contributed to an inoperable SBDG (See IR 93015). The inspector's initial evaluation of the licensee's program to periodically audit vendor manuals indicated that there was a lack of adequate management attention. This result was similar to the licensee's internal quality assurance audit of vendor information control (number I-92-08), dated September 1992. The licensee's vendor control program appeared to adequately review new changes to the technical manuals. However, it had never adequately reviewed safety-related manuals to ensure that the surveillance, maintenance, and preventative maintenance recommendations were either followed or justification was provided for deviation. In January 1994 there was a backlog of approximately 1500 safety- and nonsafety-related vendor manuals which required review. That backlog was the result of a self-assessment in early 1992 that required re-review of approximately 3300 vendor manuals. The licensee stated that there was no specific priorities assigned to the review of the manuals. The licensee was requested to include the plans to improve the vendor information control program in the response to the Notice of Violation (331/94002-02(DRP)).

b. <u>Reactor Core Isolation Cooling (RCIC) Steam Line Pressure Switches</u>

On January 12, 1994, with the reactor at approximately 100 percent power, three of the four pressure switches failed quarterly STP 42A021-Q, "RCIC Steam Supply Pressure Low Functional and Calibration." Each of the Barksdale bourdon tube pressure switches were recalibrated and returned to service prior to moving on to the next switch. The licensee notified the NRC in accordance with 10 CFR 50.72 that the RCIC steam line isolation system was not capable of performing its function. All other emergency core cooling systems were operable while the STP was being performed. The purpose of the low steam line pressure isolation was to: (1) isolate the RCIC steam supply line if a steam line break occurs upstream of the high steam flow isolation sensing elements, and (2) to isolate RCIC when steam pressure was too low to effectively operate the RCIC turbine.

The inspectors reviewed the performance trend data of the Barksdale pressure switches used in TS applications and determined that there was a history of excessive setpoint drift. The licensee had been trending the setpoint drift of some of the instruments since 1988. The trend data appeared to suggest a seasonal relationship between outside ambient temperature and the magnitude of setpoint drift. However, a clear link between the two was never established. In February 1992, the licensee started using temperature compensated test equipment to calibrate the Barksdale pressure switches in an attempt to reduce the setpoint drift. This appeared to reduce the magnitude of the setpoint drift. Additionally, the installed Barksdale pressure switches were being replaced with temperature compensated models when excessive setpoint drift was identified. Eleven of the 27 Barksdale pressure switches used in TS applications have been replaced with temperature compensated models. Additional evaluation was needed to determine if setpoint drift was still a concern for the temperature compensated models.

The inspectors were concerned that the trending program was not critically evaluating trending information because the failure of the RCIC low steam line pressure switches or the main steam line pressure switches (See IR 93023) had not been predicted. Additionally, the licensee appeared to have tolerated significant setpoint drift for a number of years. An engineering evaluation of the setpoint drift in January 1993 (letter NG-93-0342) determined that the pressure switches were performing within their expected tolerance, and that the pressure switches were to be replaced when they failed the STP due to instrument drift. The licensee's position of waiting for a failure demonstrated a lack of a questioning attitude to identify and correct the root cause of the setpoint drift. The same concern was identified for the "C" RHR pump failure (See section 4.a above).

Based on the recent failures of the main steam line and the RCIC pressure switches and on discussions with the inspectors, the licensee developed an action plan to evaluate and improve the performance of the Barksdale pressure switches. The plan included: (1) increased surveillance frequency to monthly for most of the non-temperature compensated pressure switches (as well as the main steam line pressure switches), (2) test Barksdale pressure switches to determine how temperature affects setpoint drift, and (3) review the trend data from temperature compensated Barksdale pressure switches to determine if setpoint drift had been reduced. The inspectors will continue to evaluate the licensee's corrective actions to improve the performance of the Barksdale pressure switches.

c. "A" RHR Quarterly Operability Test.

On February 1, 1994, with the reactor at approximately 100 percent power, the "A" RHR pump failed STP 45A002-Q, "LPCI System Quarterly Operability Tests," due to high pump differential pressure (D/P) and was declared inoperable. The engineering and maintenance departments evaluated the performance trending data, STP results, and maintenance history and determined that the American Society of Mechanical Engineers' (ASME) reference value for D/P (established in 1988) need to be changed. On February 3 the STP was successfully completed using the new ASME values and the "A" RHR pump was declared operable. The maintenance and engineering departments demonstrated an aggressive, questioning attitude during the troubleshooting for the failed STP.

d. HPCI System Quarterly Operability Test

On January 19, 1994, with the reactor at approximately 100 percent power, the HPCI pump failed STP 45D001-Q, "HPCI System Quarterly Operability Test", due to high D/P and was declared inoperable, but was still considered available. The licensee notified the NRC in accordance with 10 CFR 50.72 that the HPCI system was not capable of performing its function, and entered the 14 day LCO.

The licensee determined that there were inaccuracies with the measuring and test equipment (M&TE) used for turbine speed indication. On January 20 the STP was successfully performed, and the HPCI system was declared operable. The licensee determined that the STP results were invalid due to inaccuracies with the M&TE used for turbine speed indication, and that the HPCI system had been capable of performing its safety function. The licensee retracted the 10 CFR 50.72 call on January 28.

The licensee's evaluation for the failed STP included comparing data from past tests and confirming the calibration of M&TE and installed instrumentation. The licensee determined that there were differences between the hand held tachometer and the control room speed instrument indications which accounted for the higher than expected D/P. This was confirmed by the subsequent test on January 20. The subsequent test was performed using two hand held tachometers and a vibration meter as a backup indication of HPCI turbine speed. The inspectors noted good coordination between the engineering, operations, and maintenance departments during the assessment and diagnosis of the problem.

Prior to performing the second test, the licensee modified STP 45D001-Q to eliminate all unnecessary steps, such as timing motor operated valves. The inspector reviewed the test modifications and acknowledged that the need for stop watches had been eliminated. This was corrected prior to performing the STP. The inspector observed good communications and "repeat backs" both inside and outside of the control room. The inspector also noted good team work between the control room operators and OSS, especially when considering the LPRM Group A power supply failure and a main turbine oil high temperature alarm during the HPCI test.

One violation and no deviations were identified in this area.

6. Report Review (90713)

During the inspection period, the inspectors reviewed the licensee's monthly operating report for January 1994. The inspectors confirmed that the information provided met the requirements of TS 6.11.1.C and Regulatory Guide 1.16.

No violations or deviations were identified in this area.

7. Inspection Followup Items

Inspection Followup 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 Inspection Followup Item disclosed during the inspection is discussed in Section 2.b.

8. Violations For Which A "Notice of Violation" Will Not Be Issued

The NRC uses the Notice of Violation to formally document the failure to meet a legally binding requirement. However, because the NRC wants to encourage and support license initiatives for self-identification and correction of problems, the NRC will not issue a Notice of Violation if the criteria set forth in Section VII.B of the "General Statement of Policy and Procedure for NRC Enforcement Actions," (Enforcement Policy, 10 CFR Part 2, Appendix C) are met. Violations of regulatory requirements identified during the inspection for which a Notice of Violation will not be issued are discussed in Sections 2.a and 2.c.

9. Exit Interview (30703)

The inspectors met with licensee representatives (denoted in Section 1) on February 7, 1993, and informally throughout the inspection period and summarized the scope and findings of the inspection activities. The inspectors also discussed the likely information content of the inspection report with regard to documents or processes reviewed by the inspectors. The licensee did not identify any such documents or processes as proprietary. The licensee acknowledged the findings of the inspection.