U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-331/91003(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 5 through February 20, 1991

Inspectors: M. Parker
C. Miller
J. McCormick-Barger
D. Hartland
J. Schapker

Approved: J. McCormick-Barger for R. L. Hague, Chief
Reactor Projects
Section 3C

3/1/91
Date

Inspection Summary

Inspection on January 5 through February 20, 1991 (Report No. 50-331/91003(DRP))
Areas Inspected: Routine, unannounced inspection by the resident and region based inspectors of followup; licensee event report followup: followup of events; operational safety; maintenance; surveillance; plant trips; allegations; organization; and report review.
Results: One violation, one non-cited violation, and one open item were identified this period. An executive summary follows:

Operations

The reactor was operating at full power at the beginning of the period. On January 6, 1991, the reactor was manually scrammed due to an unisolable leak on an extraction steam line (Section 8.a.). Following extraction steam line repairs, the reactor was taken critical on January 8, 1991. The reactor was shutdown on January 16, 1991, to repair steam leaks on feedwater seal return piping, HPCI drains, and the offgas system (Section 6.a.). After completion of repairs, the reactor was taken critical on January 22, 1991. On February 16, 1991, the reactor automatically scrammed during turbine testing (Section 8.b.). Following repairs of the turbine control system, the reactor was taken critical on February 13, 1991. The reactor was administratively limited to 97% power during the rest of the period due to feedwater flow transmitter inaccuracies.

On January 22, 1991, the licensee exceeded the Technical Specification heatup rate. A non-cited violation was issued (Section 5.a.).

The inspectors reviewed the licensee's practice of bypassing APRM channels for long periods, and inadequate controls on APRM GAF settings. An open item was issued to follow corrective actions (Section 5.b.).

Maintenance/Surveillance

Steam leaks on 2" and less diameter piping caused a reactor scram on January 6, 1991, and a shutdown on January 16, 1991 (Section 6.a.).

Engineering and Tech Support

The licensee failed to take corrective action for feedwater flow errors identified in a 1988 GE Service Information Letter and for transmitter drift problems identified in transmitter calibrations. A Notice of Violation was issued (Section 6.b.).

DETAILS

1. Persons Contacted

 R. Anderson, Testing and Surveillance Supervisor
 R. Anderson, Assistant Operations Supervisor
*R. Baldyga, Response Engineering Supervisor
 P. Bessette, Senior Licensing Engineer
*D. Blair, Group Leader, Internal Audits
*C. Bleau, Systems Engineering Supervisor
 M. Brandt, Reactor Engineer
*A. Browning, Supervising Engineer, Licensing
*V. Crew, Technical Support
*J. Edom, Reactor and Computer Performance Supervisor
 D. Englehardt, Security Supervisor
 D. Fowler, Operations Shift Supervisor
 H. Giorgio, Radiation Protection Supervisor
 R. Hannen, Outage Manager
*B. Hopkins, Analysis Engineering
 M. Huting, Quality Control Supervisor
 B. Lacy, Manager, Design Engineering
*D. Mankin, Quality Assurance Surveillant
*M. McDermott, Maintenance Superintendent
 R. McGee, Technical Support Engineer
*C. Mick, Operations Supervisor
 W. Miller, Supervising Engineer, Analysis Engineering
*K. Peveler, Corporate Quality Assurance Manager
 J. Probst, Technical Support Engineer
*K. Putnam, Technical Support Supervisor
 B. Schenkelberg, Fire Protection Supervisor
 S. Swails, Training Superintendent
*J. Thorsteinson, Assistant Plant Superintendent, Operations Support
*G. Van Middlesworth, Assistant Plant Superintendent, Operations
 J. West, Acting Supervisor, Engineering Evaluation and Practices
*D. Wilson, Plant Superintendent, Nuclear
*S. Winter, System Engineer
*K. Young, Assistant Plant Superintendent, Radiation Protection

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 26, 1991.

2. Followup (92701) (92702) (82701)

a. (Closed) Open Item 50-331/88200-09: Desktop Simulations. This item was opened as a result of an Emergency Operating Procedure (EOP) team inspection conducted in August 1988, which concluded that the operating crew evaluated lacked a detailed familiarity with the more remote actions required by EOPs.

A followup EOP team inspection conducted in October 1989 observed the performance of an operating crew on the Duane Arnold simulator for two scenarios. Although the simulator had not yet been fully validated, and therefore, had not yet been fully integrated into the training program nor used to validate the revised EOPs, the team concluded that operator performance using the EOPs was acceptable (see Inspection Report 331/90002(DRP)). This item, however, remained opened pending a more detailed evaluation of operator familiarity with the EOPs.

During the course of an Operational Evaluation conducted on August 13-17, 1990, following EOP deficiencies identified during a routine requalification exam, special attention by the operator examiners was made to monitor previously identified deficiencies. The results of this evaluation determined that the operating crews performed adequately. The SROs adequately demonstrated their command/control, and cognitive skills with the EOPs. Overall, the crews showed marked improvement from the previous exam, and all previously identified deficiencies were adequately resolved. This open item is closed.

b. <u>(Closed) Violation 50-331/89022-03:</u> The licensee made changes to surveillance test procedure (STP) 47C001 without concurrence of two members of the plant management staff or subsequent review of the Operations Committee. The inspectors reviewed the licensee's corrective actions for this violation. A memorandum was prepared on December 7, 1989, from the plant manager to plant staff to provide written direction to strengthen the policy concerning procedure control and adherence. The memorandum adequately emphasized the need for plant staff to correct procedural problems rather than circumvent them. The issue concerning performance of the surveillance test (STP 47C001) at wind speeds greater than 5 miles per hour has been referred to the Office of Nuclear Reactor Regulation (NRR) and will be addressed separately.

Following identification of this violation, additional procedural violations were identified during the 1990 cycle 10/11 refuel outage and will be documented in the followup of item 331/90017-5F. This item is closed.

c. <u>(Closed) Violation 50-331/89026-01:</u> This violation concerned the failure of the licensee to establish an adequate surveillance test to demonstrate that the Standby Gas Treatment System (SGTS) could maintain 1/4 inch of water vacuum under calm wind conditions with a filter train flow rate of not more than 4000 SCFM. The previous surveillance test was found to be inadequate because it did not consider the effects that other operating ventilation systems would have on the test results. In response to the violation, the licensee revised its secondary containment operability test procedure to require that the main plant exhaust, turbine building and radwaste building ventilation systems be secured during the test. The licensee also reviewed all other STPs applicable to safety-related heating, ventilation, and air condition (HVAC) systems to determine whether other previously unknown interactions could affect the accuracy of test results. The licensee reported that no deficiencies were identified in the other test procedures.

The inspectors reviewed STP 47C001-CR, "Secondary Containment Integrity", revision 3, dated December 28, 1990, and found it to reflect the changes identified in the Notice of Violation response. The inspectors also verified that operating and alarm response procedures were revised, as specified in the violation response, to require that the main plant exhaust fans be secured upon receipt of a reactor building vent stack radiation alarm during secondary containment isolation conditions. The inspectors also verified that the licensee's preventive maintenance program included inspection and repair of boot and airlock door seals. In addition, results of three recently performed tests were reviewed and found to meet the requirements specified in the Technical Specifications.

The licensee also committed to perform an inspection of all Class 1 duct work to verify that the as-built configuration meets the applicable design specifications. The licensee originally committed to complete this inspection by December 31, 1990. During the 1990 cycle 10/11 refuel outage, the licensee conducted inspections of its inaccessible Class 1 duct work. Based on finding only minor discrepancies and the existence of higher priority work, the licensee revised its Class 1 duct work inspection completion date to June 30, 1991, in a letter to the NRC dated November 7, 1990. Completion of the duct work inspection will also be reviewed during closure of LER 89-012 (331/89012-LL). This item is considered closed.

d. (Closed) Violation 50-331/90011-01: The 1989 annual audit of the Emergency Preparedness (EP) program, which was reviewed in June 1990, did not satisfy the requirements of 10 CFR 50.54(t), since it did not include an evaluation of the adequacy of the licensee's interface with appropriate state officials.

The draft Quality Assurance (QA) Audit Plan for the 1990 audit was reviewed during the November exercise inspection. It included adequate provisions to address the topic areas specified in 10 CFR 50.54(t), including the interface with state and local support organizations. The final report for Audit I-90-22, which was conducted from October 8 through November 9, 1990, was reviewed. The 1990 audit was much improved in scope, depth, and the quality of its documentation compared to the 1989 audit records that had been reviewed. The 1990 audit adequately addressed all the topic areas specified in 10 CFR 50.54(t). The licensee's provisions for providing relevant 1990 EP audit results to state and county officials will be reviewed during a future inspection. This item is closed.

3. Licensee Event Reports Followup (92700) (90712)

Through direct observations, discussions with licensee personnel, and review of records, the following event reports were reviewed to determine that reportability requirements were fulfilled, immediate corrective action was accomplished, and corrective action to prevent recurrence had been accomplished in accordance with technical specifications.

a. (Closed) Licensee Event Report (LER) 88-015 (331/88015-LL): High Pressure Coolant Injection Turbine Reversing Chamber Failures. This LER was one of three LERs (LERs 85-007, 87-007, and 88-015) that have been issued to the NRC to provide information concerning High Pressure Coolant Injection (HPCI) turbine steam reversing chamber cracks or damage. As in previous refuel outages, the licensee repaired the discrepant reversing chambers. Previous attempts to determine the root cause or to identify a lasting corrective action had been unsuccessful. These attempts included replacing damaged components and using specially heat treated reversing chambers.

During the cycle 9/10 refuel outage, the licensee again replaced the deficient reversing chambers with stock from its warehouse (not specially heat treated). They also replaced the electro-mechanical hydraulic actuator that controlled the steam that impinged on the subject reversing chambers. During the cycle 10/11 refuel outage, the licensee modified steam inlet valve operation. Both the actuator and the inlet valve work was performed in an attempt to ease the pressure pulsing fatigue associated with initial HPCI turbine startups. The licensee did not inspect the steam reversing chambers during the cycle 10/11 refuel outage but plan to during the cycle 11/12 refuel outage.

Based on the licensee's operating experience and supported by the HPCI turbine vendor, Terry Turbine Company, the licensee believes that broken or cracked reversing chambers have no effect on the ability of the system to perform its design function. Although the licensee expects that the changes made to the actuator and inlet valves will reduce the load on the reversing chambers, they expect some damage to be found during the next inspection. The licensee plans to continue monitoring the performance and condition of the reversing chambers. This item is closed.

b. (Closed) Licensee Event Report (LER) 89-011 (331/89011-LL) and Rev. 1 (331/89011-1L): Turbine Control Valve Fast Closure Trip Results in Reactor Scram While Performing Testing. During performance of a weekly surveillance test of the power/load unbalance circuit, the plant received a main turbine trip and a reactor scram. This event was due to an invalid load reject signal because the test circuit failed to reset after being tested. The licensee reported that they believed the cause of the failure of the circuit to reset was the bridging of a mercury-wetted relay in the power/load unbalance circuitry.

The inspectors reviewed the corrective actions taken by the licensee to prevent recurrence. The licensee performed a design change to the power/load unbalance test circuitry to prevent inadvertent turbine trips if the circuitry fails to reset following testing. They also changed test procedures to caution the operators on what to do if the circuitry fails to reset.

Following the turbine trip, the "B" non-essential bus failed to properly transfer from the auxiliary transformer to the startup transformer, resulting in the loss of both the "B" essential and non-essential buses. The "B" Emergency Diesel Generator started and assumed the required essential loads. The failure of the non-essential bus to properly transfer was reported to have been because the trip coil, associated with the non-essential bus breaker to the auxiliary transformer, did not trip the breaker, as required during bus transfer, resulting in the non-essential bus being tied to both the auxiliary and startup transformers at the same time. The licensee found that the trip coil slug had become cocked slightly, preventing the coil from energizing and tripping the breaker. The root cause of the trip coil failure was determined to be age related wear.

The inspectors reviewed the licensee's preventive maintenance program and identified that all 4160 volt breaker trip coils are to be inspected and, if necessary, replaced over a 5 year cycle. About one-third of all trip coils will be inspected during each refueling outage. Following the trip, the licensee tested all trip coils using a lower voltage across the coil as a test for acceptance (the vendor informed the licensee that a lower voltage would be more likely to cause the trip coils to fail if worn). The licensee replaced one additional trip coil due to the low voltage test. This LER is closed.

c. <u>(Open) Licensee Event Report (LER) 89-015 (331/89015-LL):</u> Reactor Water Cleanup Isolation Due to a High Differential Flow Condition While Placing a Filter Demineralizer Bed In Service. The licensee stated that the RWCU high differential flow and subsequent isolation was due to a combination of the reactor being at atmospheric pressure and an air bubble within the "A" filter demineralizer. They committed in the long term to install hardware necessary to manually vent and fill the RWCU filter/demineralizers prior to placing them in service.

Subsequent to issuing the LER, the licensee changed its high differential flow isolation time delay circuit from 15 seconds to 45 seconds as advised by the vendor. The RWCU isolation had occurred

18 seconds after putting the system in-service. The licensee now suspects that the time delay change may have resolved the issue. They plan to continue to monitor RWCU performance and may decide to revise their LER to withdraw their commitment to install hardware changes to allow manual vent and fill activities.

This LER will remain open pending the installation of a manual vent and fill system for the RWCU filter/demineralizers or the revision of the LER submitted to the NRC.

d. <u>(Closed) Licensee Event Report (LER) 90-016 (331/90016-LL):</u> Reactor Scram on Three Main Steam Lines Less Than 90% Open Due to Loose Electrical Connection Coincident With Surveillance Test Performance. This LER was generated following a reactor scram that occurred during a surveillance test. The cause of the scram was attributed to a loose wire connection in the inboard MSIV control logic located in the control room. As corrective actions, the licensee performed inspections of appropriate control room panels to check for additional loose connections. They also initiated a Preventive Maintenance (PM) inspection list that covered all safety related panels and those considered by the licensee to be critical to plant operation.

The inspectors were informed that additional inspections of control room panels, performed prior to restart following the reactor trip, identified several other loose connections and minor housekeeping deficiencies that were immediately corrected. A review of the PM program for loose electrical terminal inspections indicated that the program was extensive, with about one-third of the panels being inspected during each refuel outage. This LER is closed.

No violations or deviations were identified in this area.

4. <u>Followup of Events (93702)</u>

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 on-site 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 6, 1991	-	Manual Reactor Scram due to an unisolable extraction steam line leak. (See Section 8 for further details.)
January 16, 1991	-	Forced Reactor Shutdown to repair unisolable steam leak on "A" reactor feedwater pump seal water return line. (See Section 6 for further details.)

February 9, 1991 - Automatic Reactor Scram on Control Valve fast closure due to Electro Hydraulic Control Fluctuations during turbine testing. (See Section 8 for further details.)

No violations or deviations were identified in this area.

5. 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 and regularly toured the plant. 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/cleanliness conditions and verified implementation of radiation protection controls. During the inspection, the inspectors walked down the accessible portions of the Standby Liquid Control 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, 10 CFR, and administrative procedures.

a. Exceeding Technical Specification Heatup Rate

On January 22, 1991, during a reactor startup, the licensee exceeded the Technical Specification (T.S.) heat up rate of 100°F per hour. The reactor had previously been taken critical and a normal heat up was in progress. Operators were monitoring heatup rate in accordance with Surveillance Test Procedure (STP) 46A003, which requires logging heatup and cooldown rates at least every fifteen minutes. During a 30 minute period starting at 3:00 a.m. (CST), the heatup rate was 180° F/hr as measured and logged for the bottom head drain temperature element. A similar heatup rate was seen on recirculation pump suction temperature indications. At 3:25 a.m. (CST), operators began inserting control rods to control the heatup rate, but this effort was not in time to prevent exceeding the 100° F per hour limit. The maximum rate achieved for a one hour period during the startup was 105° F per hour. The inspectors were especially concerned that problems with balance of plant equipment had diverted operators' attention from reactor conditions, even though a sufficient staff was available in the control room to monitor reactor heatup. At the time of the event, the operators were experiencing great difficulty in starting up the circulation water (CW) system due to severe cooling tower icing problems caused by extremely low outside temperatures.

The inspectors discussed the heatup rate excursion with members of the operating crew on shift at the time of the event. Although the problems caused by the CW icing problems required the presence of an Operating Shift Supervisor at the towers, the inspectors determined that adequate personnel were available in the control room to monitor the reactor startup. The shift personnel had performed the temperature monitoring required by the procedure and had taken some corrective actions to minimize the heatup rate. When the 3:15 a.m. (CST) readings indicated a 180° F/hr heat up rate, the shift stopped pulling rods. At 3:25 a.m. (CST) the operators determined that additional action was needed to curb the reactor heatup. At this point they began inserting control rods. This action eventually curbed the heatup to the maximum of 105° F for a one hour period. Further heatup during this startup was controlled well within the T.S. limits.

The inspectors reviewed integrated plant operating instructions (IPOI) to determine what limits were placed on heatup rate. The startup procedure (IPO12) requires a maximum heatup rate of 100° F/hr in the body of the procedure and in the precautions. The inspectors noted that there was no administrative limit in the procedure to prevent operators from exceeding the T.S. heatup rate. The operating shift agreed that this type of control may help prevent a heatup rate excursion.

Licensee corrective actions after immediately reducing the heatup rate have focused primarily on correcting personnel errors. Personnel involved with the heatup incident received disciplinary action. In addition, part of the shift involved in the heatup developed and administered training to the rest of the operating shifts on the incident. Improved methods of monitoring heatup rate are also being considered by the licensee since the present method of logging temperatures does not easily give the operators a quick reference of how actual heatup rate compares to the limit.

T.S. 3.6.A.1 states that the average rate of reactor coolant temperature changes during normal heatup shall not exceed 100° F/hr when averaged over a one hour period. Contrary to this T.S., the heatup rate during the period of 2:45 a.m. to 3:45 a.m. (CST) on January 22, 1991, was 105° F/hr as measured on the recirculation suction and bottom head drain temperature elements. This failure to abide by T.S. requirement is considered a violation (331/91003-01 (DRP)). However, in accordance with Section V.G.1 of 10 CFR 2, Appendix C, this violation will not be cited.

b. APRM Reliability

The inspectors reviewed deviation report (DR) 90-332 which described a condition in which two Average Power Range Monitor (APRM) channels were reading non-conservatively low for a two hour period during a reactor power increase following startup. Previous to this incident, the inspectors had expressed concern that the licensee had chosen to address the problem of spiking on shared Local Power Range Monitors (LPRMs) by bypassing two APRM channels during startup and normal power operations. This condition, although allowed for an unspecified period by Technical Specifications (T.S.), represents a decreased power range monitoring and trip capability.

On the reactor startup conducted on December 16, 1990, for which DR 90-332 was written, the APRM gain adjustment factors (GAFs) were allowed to go as high as 1.13. The inspectors also observed the reactor startup concluded on January 8, 1991, after DR 90-332 was issued, and observed GAFs of up to 1.12. A GAF of 1.0 or less represents a conservative APRM reading compared to the core thermal heat balance. During the December 16, 1990, startup, APRM D reached a GAF of 1.09 or 9% non-conservative, and APRM C reached a GAF of 1.13, or 13% non-conservative. At the same time, APRMs A and D were bypassed. This condition left only APRM E available on the A RPS Channel to initiate a reactor protective trip at the proper setpoint. A full reactor scram at the proper setpoint would not have been possible had APRM E not been functional. This condition does not appear to satisfy reactor protective system redundancy requirements since APRM GAFs change routinely during reactor startup, and the licensee has no limit on the amount of non-conservatism allowed. The inspectors expressed their concerns about APRM reliability to the licensee staff. The licensee is presently evaluating DR 90-332 for corrective action. Two computer points have since been modified to alarm, one when APRM power reached less than 94% of thermal power, and one when a GAF reaches 1.04. The licensee is also considering setting administrative limits to guide operators as to acceptable GAF setpoints. Additionally, a procedure change to the rod pull sheets, used for startup by operators to check GAF settings, is being considered. At the close of the inspection period, licensee engineers were evaluating the feasibility of unbypassing APRMs at high power levels where a spike on a shared LPRM could not cause a reactor scram. The licensee's corrective actions for maintaining APRM reliability will be reviewed in further inspections as open item 331/91003-02.

6. Monthly Maintenance Observation (62703)

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

The following items were considered during this review: the limiting conditions for operation were met while components or systems were removed from service; approvals were obtained prior to initiating the work; 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 may affect system performance.

The following maintenance activities were observed/reviewed:

HPCI Steam Drain Line repair

PASS troubleshooting and repairs

Feedwater Flow Transmitter calibrations

Turbine EHC System troubleshooting

Overhaul of Limitorque Operator for Valve MO1912, PMAR 1048693

Overhaul of Limitorque Operator for Valve MO1920, PMAR 1048694

Overhaul of Limitorque Operator for Valve MO1921, PMAR 1048695

Overhaul of Limitorque Operator for Valve MO1913, CMAR A03814

a. <u>Steam Leaks</u>

The reactor was shutdown on January 16, 1991, to repair several steam leaks. During a routine inspection on January 12, 1991, the licensee discovered an unisolable steam leak on the "A" feed pump seal water return to feedwater heater 4A, and leaks on the HPCI and offgas systems which required the plant to be in cold shutdown for repairs. Approximately 200 feet of pipe was replaced in the feedwater, HPCI, and offgas systems due to thru wall leaks or wall thinning. The inspectors noted that the licensee has no current program to inspect or monitor erosion for small bore piping which is susceptible to two phase flow.

During the outage, the licensee also installed a modification to sprinkler system #4 which reduced the head loss of the sprinkler system inside the heater bay. This will serve to reduce the rated head and flow requirements of the DAEC fire pumps once Technical Specifications are changed accordingly.

b. <u>Exceeding Licensed Thermal Power</u>

During a review of industry problems with transmitter calibrations, the licensee discovered that the feedwater (FW) flow transmitters which supply computer input to the thermal heat balance had exhibited a non-conservative drift during the last refueling outage. The licensee's initial review of the as found data taken during July 1990 determined that one transmitter (FT 1581) was 2.8% out of tolerance, the other (FT 1626) was 1.12% out of tolerance. The licensee determined this to have caused the indicated thermal power to read over 1% low at 100% power. The inspectors reviewed the feedwater transmitter calibration data sheets and determined the actual drift to have been 3.5% and 1.4% respectively. Licensee engineers agreed with the inspectors assessment of the drift errors.

Further review of the calibrations by the licensee and the resident inspectors indicated that the licensee had not calibrated the FW flow transmitters at rated FW pressure. The transmitters are Rosemount 1151 D/P models, which exhibit a span shift when operating at pressures different than the pressure at which they are calibrated. This span shift had the possibility of introducing additional non-conservative errors into the feedwater flow transmitter signal. The inspectors discussed with the licensee their concerns that thermal power limits had apparently been exceeded in the past and were still possibly being exceeded due to improper transmitter calibrations. The licensee agreed to perform an expeditious review of transmitter flow calibration effect on present thermal power, and to compare previous core thermal power excursions to design basis transient analysis thermal power assumptions.

On February 12, 1991, prior to reactor startup from the February 9, 1991, reactor scram, the licensee calibrated both FW flow transmitters to include an offset for operating pressure. This calibration showed that an additional 1.8% non-conservative error had been introduced into the FW flow transmitter signal from failure to include this offset. At the close of the inspection period, the licensee was still determining what effect the drift and pressure set errors had on operating near thermal power limits.

Errors with FW flow instrumentation were documented in GE RICSIL 30 received by the licensee in October 1988, and GE SIL 452, Supplement 1, issued November 18, 1988. A commitment to address the concerns of the SIL had been implemented into the licensee's commitment control program; however, the deadline to review the SIL had been exceeded. The SIL mentioned several inaccuracies in feedwater flow calibrations which have the potential to introduce a non-conservative bias in thermal power calculations. The inspectors noted that a period exceeding two years had passed since the licensee had received the RICSIL, until the February 12, 1991, calibrations. The licensee is still evaluating other corrective actions described in the SIL and RICSIL.

On February 14, 1991, while reviewing the calibration histories of FT 1581 and FT 1626, the inspectors discovered that a second calibration had been required for FT 1581 earlier that day. Since its calibration on February 12, 1991, FT 1581 had drifted up to eight percent in the non-conservative direction. The inspectors questioned licensee maintenance and engineering staff to determine if the transmitter was repaired or would continue to drift, and to determine the guidance given to plant operators on the accuracy of indicated thermal and APRM power. The inspectors were informed that the transmitter had been calibrated but not repaired, and that both transmitters showed a history of drifting and would be replaced. Maintenance planners also informed the inspectors that although replacement transmitters had been ordered, they would not arrive for several weeks. At this time, the plant had commenced a startup from the February 9, 1991, scram but had not achieved full power. The inspectors interviewed the operations shift supervisor and assistant operations supervisor and determined that no special guidance had been given to alert them of potential inaccuracies with feedwater flow indications and thermal power readout. A deviation report (DR) had been written to document the transmitter calibration, but no indication was given in the DR or to operators that the problem was not corrected. On February 15, 1991, plant engineers and maintenance staff then devised a method to compare FW flow transmitter readings with local differential pressure indicators in order to monitor possible drift of FT 1586 and FT 1626. Plant thermal power was administratively limited first to 98%, then to 97% power, as a result of these comparisons. The inspectors are continuing to review the results of the transmitter comparisons and other parameters to assure plant licensed thermal power limits are not exceeded.

The inspectors noted an overall lack of appreciation for the importance of the information supplied by the feedwater flow transmitters. The transmitter output is a major input to the thermal power calculation, which is in turn used to calibrate APRMs. The licensee had already issued a licensee event report in 1979 due to DAEC FW flow errors causing licensed thermal power excursions; yet plant engineering, maintenance, and operations staff did not appear to devote the priority and attention needed to keep FW flow output accurate. The inspectors review of FW flow transmitter calibrations revealed that calibrations performed on both transmitters since November 1988 had "as-found" readings out of allowable tolerance. Despite this, no trending or increased calibration frequencies had been initiated. A system engineer wrote two corrective maintenance action requests (CMAR 095725 and 095726) in December 1989 describing a 2% increase in FW flow indication compared to turbine first stage pressure. These CMARs were not worked until the July 1990 outage. The inspectors noted that at DAEC, FW flow transmitters and other inputs to the thermal power calculation are quality level 4 instruments, non-safety related. The licensee is presently evaluating ways to increase the level of quality oversight which these instruments receive.

Failure to take adequate corrective actions for feedwater flow calibration errors is considered a violation (331/91003-03 (DRP)) of 10 CFR 50, Appendix B, Criterion XVI (Corrective Action).

c. "B" RHR Motor Operated Valve Maintenance

The four valve operators identified above were overhauled as part of the licensee's preplanned maintenance program. The licensee was specifically concerned that damage may have occurred to the valves due to past over thrusting. Specific penetrant testing of bevel gear housing was conducted with no damage identified. Portions of valve removal, disassembly, inspection, reassembly, reinstallations, and testing were observed. No concerns were identified.

Following completion of maintenance on the HPCI and RHR Systems, the inspectors verified that these systems had been returned to service properly.

7. Monthly Surveillance Observation (61726)

The inspectors observed technical specifications 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 technical specifications 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 also witnessed portions of the following test activities:

STP-41A013-Q	-	Steam Line High Radiation Instrument Channel Calibration
STP-45A001-LCO	-	Core Spray System Operability Test
STP-45C001-Q	-	RHRSW Operability Test
STP-45G001	-	One Standby Diesel Generator Inoperable Test
STP-48A001-M	-	Standby Diesel Generators Monthly Operability Test
STP-413B004	-	Diesel and Electric Driven Fire Pump Demonstration

No violations or deviations were identified in this area.

8. Plant Trips (93702)

Following the plant trips on January 6 and February 9, 1991, the inspectors ascertained the status of the reactor and safety systems by observation of control room indicators and discussions with licensee personnel concerning plant parameters, emergency system status and reactor coolant chemistry. The inspectors verified the establishment of proper communications and reviewed the corrective actions taken by the licensee.

a. January 6, 1991

The reactor was manually scrammed on January 6, 1991, due to an unisolable steam leak on a 2 inch extraction steam line. All safety systems functioned normally, including PCIS Group II through V isolations which were received on low reactor vessel level resulting from void collapse following the scram. A notification of unusual event (NOUE) was declared at 11:30 a.m. (CST) on January 6, 1991, due to a hazard requiring other than normal shutdown. The NOUE was cancelled at 12:00 a.m. (CST) that same day.

The licensee had discovered the steam leak on the extraction steam piping on January 5, 1991, during a routine heater bay inspection. The decision was made not to repair the leak at that time. At about 10:14 a.m. (CST) on January 6, 1991, a security guard reported that steam was coming from the turbine operating deck. Operators at that time determined the source to be a failure in the extraction steam line in the heater bay and began a controlled plant shutdown. At 11:00 a.m. (CST) on the same day, operators noticed the main steam line detector temperatures in the heater bay increasing rapidly, and only 15° F away from the PCIS Group 1 (MSIV) isolation setpoint. At this point, the decision was made to reduce recirculation speed to the minimum and insert a manual scram.

The failed piping was at a "tee" connection in the extraction steam piping to the number 6 feedwater heaters. This connection had been repaired twice since 1989.

The plant remained in a hot shutdown condition while repairs were made to the pipe. A piping modification was made which added an expansion loop to the 2 inch extraction steam line in order to reduce fatigue failure at the weld where the 2 inch line met the 10 inch header.

Following repairs to the extraction steam line, the licensee commenced a reactor startup on January 8, 1991, and the reactor was declared critical with an 85 second period.

b. February 9, 1991

On February 9, 1991, the reactor automatically scrammed during routine turbine overspeed trip device testing. The scram occurred immediately after operators pushed the mechanical trip reset button. No reactor pressure or power spikes were observed as a result of the testing. All safety systems responded normally following the scram, including PCIS Groups II thru V isolations resulting from reactor vessel level shrink.

The licensee could not conclusively determine the chain of events which caused the scram. Extensive troubleshooting within the turbine electro hydraulic control (EHC) system indicated the following problems. The primary speed sensing circuit had a 16% calibration error. Shielding on the primary speed cable was made ineffective by grounding. The pressure set potentiometer drive motor was missing its shielding, and was found to induce a noise on the speed error signal. Since the turbine intercept and bypass valves fluctuated during the event, the licensee postulated that the turbine control system sensed a temporary overspeed condition due to induced noise. The noise signal was present long enough to cause the intercept valves to move. This caused EHC pressure to momentarily drop low enough to pick up the RPS fast closure pressure switches. This scram mechanism was similar to a scram in 1983 for which all corrective actions had not been completed.

The licensee completed repairs to the turbine control system and instrumented the intermediate valve, control valve, and speed control parameters for further testing. In addition, the licensee recalibrated the feedwater flow transmitters to incorporate a static pressure compensation. The reactor was taken critical on February 13, 1991, with a 63 second period. Turbine testing conducted prior to paralleling the turbine to the grid, and again prior to exceeding bypass valve capacity, indicated no further problems with the EHC system.

No violations or deviations were identified in this area.

9. Allegation Followup

(Closed) Allegation (AMS RIII-90-A-0087): The NRC received an allegation from a former licensee contractor employee. The issues were non-specific and concerned alleged Weld Procedure Specifications (WPS) and supporting Procedure Qualification Records (PQR) that did not meet the American Society of Mechanical Engineers (ASME) Code requirements or were otherwise deficient. Attempts to obtain specific details from the concerned individual were unsuccessful.

Through discussions with the concerned individual, the inspectors deducted the most probable WPSs/PQRs and selected these for review. In addition, a random sample of additional WPSs/PQRs were also reviewed. The results of this review did not identify any ASME Code violations as described by the concerned individual.

Further attempts to contact the individual to discuss the concerns were unsuccessful. The telephone number previously used to contact the individual was disconnected. A letter was sent to the individual's latest reported address with no reply.

Based on the review performed by the inspectors, which disclosed no violations of ASME Code requirements, this allegation is closed.

10. <u>Organization (36800)</u>

The inspectors conducted an inspection to verify that changes to the licensee's organization and organizational structure conformed to license requirements, that appropriate administrative procedures were adhered to, and approvals were obtained as required by the license and the licensee's procedures.

Major site personnel changes during the SALP period included the appointment of a new Quality Control Supervisor, Maintenance Superintendent, Assistant Plant Superintendent-Operations Support, and Manager of Nuclear Training. In addition, due to the organizational structure change which resulted in the reorganization of the Radiation Protection and Security Departments, a new person was designated as the Radiation Protection Manager. The inspectors reviewed the resumes of the new appointees to these positions and confirmed that their qualifications conform to licensee technical specifications.

The licensee's administrative procedure No. 113.2, "Records of Training", is used as a mechanism for documenting that employees transferring to different positions meet appropriate qualifications. The supervisor of the employee transferring to the new position is required by the procedure to forward a completed "ANSI/ANS - 3.1, 1978 Employee Qualification Record" (EQR) to the DAEC Training Center within thirty (30) days of the date when the promotion/transfer becomes effective. The EQR is to be maintained in the employee's personnel training file at the training center.

The inspectors discovered that this documentation of personnel qualifications was not being performed. However, the licensee was aware of this discrepancy and has committed to revising the EQR form to reflect upgraded position descriptions and include means of documenting how an individual meets the appropriate standard for their current position. The procedure will also be revised to include sufficient instruction for using and properly completing the forms. Training on the purpose and use of the revised EQR procedure/form will reportably be provided. The inspectors were satisfied with the licensee's commitment to resolve the deficiency.

Overall, the inspectors concluded that the licensee organization changes were adequate and met regulatory requirements.

No violations or deviations were identified in this area.

11. Report Review (90713)

During the inspection period, the inspectors reviewed the licensee's Monthly Operating Reports for December 1990 and January 1991. The inspectors confirmed that the information provided met the requirements of Technical Specifications 6.11.1.C and Regulatory Guide 1.16.

No violations or deviations were identified in this area.

12. Open Items

Open items are matters which have been discussed with the licensee, which will be reviewed further by the inspectors, and which involve some action on the part of the NRC or licensee or both. An open item disclosed during the inspection is discussed in Paragraph 5.b..

13. Violation for Which a "Notice of Violation" Will Not be Issued

The NRC uses the Notice of Violation as a standard method for formalizing the existence of a violation of a legally binding requirement. However, because the NRC wants to encourage and support licensee initiatives for self-identification and correction of problems, the NRC will not generally issue a Notice of Violation for a violation that meets the tests of 10 CFR 2, Appendix C, Section V.G.1. These tests are: (1) the violation was identified by the licensee; (2) the violation would be categorized as Severity Level IV or V; (3) the violation was reported to the NRC, if required; (4) the violation will be corrected, including measures to prevent recurrence, within a reasonable time period; and (5) it was not a violation that could reasonably be expected to have been prevented by the licensee's corrective action for a previous violation.

Violation for which a Notice of Violation will not be issued is identified in Paragraph 5.a of this report.

14. Exit Interview

The inspectors met with licensee representatives (denoted in Paragraph 1) on February 26, 1991, 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.