U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-331/91016(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: September 30 through November 11, 1991

Inspectors: M. Parker
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Approved: J. W. McCormick-Barger for 11/21/91
R. L. Hague, Chief Date
Reactor Projects
Section 3C

Inspection Summary

Inspection on September 30 through November 11, 1991 (Report No. 50-331/91016(DRP))

Areas Inspected: Routine, unannounced inspection by the resident inspectors and region based inspectors of licensee event reports followup; operational safety; maintenance; surveillance; information meeting with local officials; cold weather preparations; regional request; management meetings; and report review.

Results: An executive summary follows:

Operations

Plant performance has been good, with no major events occurring this period. DAEC set new annual power production records as well as achieving the third longest continuous run in DAEC history this period. The plant operated at or near 100% power throughout the period, with short down power periods for load following, rod maneuvering, and performance of surveillances.

Poor coordination of maintenance and radwaste activities led to significant contamination of several locations inside the reactor building (Section 3).

The Standby Filter Units were found to have incorrect dampers installed which would not prevent backflow. An operating order was issued to have operators manually close system dampers under certain conditions. An unresolved item was issued to follow the licensee's determination of system operability and corrective actions (Section 3).

Radiological Controls

Planned cleanup of contaminated areas took a significant setback due to radiological spills and flooding in the Northeast, Northwest, and Southeast Corner rooms, as well as the RCIC room (Section 3).

Maintenance/Surveillance

Failure to perform post maintenance testing on a Main Steam Isolation Valve resulted in a violation (Section 4).

Important plant equipment was out of service for extended periods of time due to maintenance and maintenance support problems (Sections 4 and 5).

Failure to test all valves in the flow path to fire hose stations resulted in a violation of technical specifications (Section 5).

Engineering and Tech Support

A more timely review of a 1989 Engineering Work Request could have addressed a potential design problem associated with the Standby Filter Unit fan motors prior to degradation (Section 4).

Inadequate Design Change Package processing and review for a 1985 facility change appeared to be a contributing cause to the missed technical specification firewater flow path surveillance checks (Section 5).

Safety Assessment/Quality Verification

Weak oversight of commitment control items was evident from the licensee's handling of biennial review concerns expressed by the NRC in July 1990 (Section 5).

DETAILS

1. **Persons Contacted**

R. Anderson, Assistant Operations Supervisor
R. Anderson, Senior Outage Project Manager
*J. Axline, Technical Support
+ R. Baldyga, Maintenance Engineering Supervisor
P. Bessette, Licensing Engineer
+*J. Bjorseth, Assistant Operations Supervisor
*D. Blair, Group Leader, Internal Audits, Quality Assurance
+*C. Bleau, Systems Engineering Supervisor
*A. Browning, Supervising Engineer, Licensing
*S. Catron, Licensing
*C. Crew, Operations Committee
J. Edom, Reactor and Computer Performance Supervisor
*M. Flasch, Manager, Design Engineering
*T. Gordon, Electrical Maintenance Supervisor
*J. Gushue, Quality Assurance
P. Hansen, System Engineer
H. Johnson, Warehouse Supervisor
*L. Mattes, Nuclear Fuels
+*M. McDermott, Maintenance Superintendent
R. McGee, Technical Support Specialist
+*C. Mick, Operations Supervisor
*W. Miller, Supervising Engineer, Analysis Engineering
*O. Olson, Discipline/Component Engineering
*K. Peveler, Corporate Quality Assurance Manager
*R. Potts, Procedure Supervisor
*J. Probst, Technical Support Engineer
+*K. Putnam, Technical Support Supervisor
+*D. Robinson, Technical Support Engineer
+*A. Roderick, Supervisor, Testing and Surveillance
*R. Salmon, Manager, Nuclear Licensing
B. Schenkelberg, Fire Protection
*T. Sims, Technical Support
*E. Sorenson, System Engineer
*G. Taylor, Senior Radiation Engineer
+*J. Thorsteinson, Assistant Plant Superintendent, Operations Support
+ G. Van Middlesworth, Assistant Plant Superintendent, Operations
+ G. Whittier, System Engineer
+*D. Wilson, Plant Superintendent, Nuclear
*T. Wilkerson, Radiation Protection Manager
+*K. Young, Assistant Plant Superintendent

U. S. Nuclear Regulatory Commission (NRC)

*C. Miller, Resident Inspector

+*M. Parker, Senior Resident Inspector
J. McCormick-Barger, Project Engineer
+ C. Gainty, Reactor Inspector

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 November 15, 1991.
+Denotes those present at the exit interview on November 1, 1991.

2. 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) 90-003 (331/90003-LL): "Primary Containment Isolation System Actuation Due to Loss of Reactor Protection System Power Supply." On March 31, 1990, during preparation for a reactor startup, the "B" Reactor Protection System (RPS) bus tripped when the "A" Reactor Recirculation Pump was started. Loss of the "B" RPS bus resulted in a half scram and Groups I through V primary containment isolations, excluding the Main Steam Isolation Valves.

When the event occurred, the "B" RPS bus was being powered by the alternate power supply which was not provided with voltage transient protection. The normal power is supplied by a motor-generator (M/G) set which utilizes a flywheel for protection against minor upstream voltage or frequency transients. Maintenance was being performed on the RPS power supply transfer logic, requiring the alternate power line up. When the "A" Reactor Recirculation Pump was started, voltage momentarily dropped on the bus that supplied power to the Equipment Protection Assembly (EPA) breakers that provided alternate power to the "B" RPS bus. This voltage reduction caused the EPA breakers to trip on undervoltage. All systems responded as required when the "B" RPS bus tripped. The licensee restored alternate power to the "B" RPS bus and reset the primary containment isolations.

Corrective actions to prevent recurrence included changing Operating Instruction (OI) 358, "Reactor Protection System", to require that when transferring RPS power from the M/G set to the alternate power source, that essential bus 1A3 must be transferred from the startup to the standby transformer (if possible). This action would remove the RPS power source from the startup transformer which supplies numerous non-essential loads that could cause voltage transients during equipment operation. A long term action will be to change the supply of the RPS alternate power from an unregulated transformer to an Instrument AC regulating transformer. The design change package to make this change has been issued and the work is scheduled to be performed during the 1992 refueling outage. This LER is closed.

b. <u>(Closed) Licensee Event Report (LER) 90-013 (331/90013-LL):</u> "Reactor Water Cleanup Isolation Due to High Area Differential Temperature". On September 10, 1990, a Group V (RWCU) isolation occurred as a result of a high differential temperature between ventilation intake and exhaust temperatures in the RWCU heat exchanger room. The high differential temperature isolation setpoint is 14 degrees above the 100% power ambient differential temperature condition. During the 1990 outage, the inlet temperature sensor was relocated closer to the inlet air flow because its previous location was not adequate to sense a proper differential temperature. However, the design modification package which covered this relocation did not allow for another full power ambient differential temperature evaluation. The cooler air impinging on the inlet sensor in its new location was sufficient to achieve a 14 degree delta temperature increase over the old full power ambient setting, and an isolation occurred as designed. This event was originally discussed in inspection report 331/90017(DRP).

The licensee attributed this event to the failure to establish a new trip point for the temperature differential switches and inadequate procedural controls in the design change process. The licensee performed a special test to determine the proper settings for the switch. The results of the test were used as the basis for a new trip setpoint. The licensee also was in the process of evaluating its overall design engineering department performance at the time of the event and, as a result of the evaluation, performed retraining of its staff on the design change verification process. In addition, the licensee committed to incorporate the use of guidelines contained in INPO Good Practice TS-415, "Technical Reviews of Design Changes", into the design review method of the design verification process procedures.

The inspectors reviewed changes made to Nuclear Generation Division Procedure (NGDP) 1203.32, "Second Level Review and Acceptance of Procured Design Changes", Revision No. 1, dated June 8, 1989. Procedure change notice (PCN) 'A' dated January 30, 1991, to the above procedure primarily incorporated the guidelines of INPO Good Practice TS-415. The inspectors noted one significant exception in that the INPO document recommended that the reviewer use an attached checklist and provide detailed evaluations for all checklist questions that were answered "Yes" (indicating that it is applicable to the design change) or marked with an asterisk. The licensee's procedure did not require a detailed evaluation for the questions, only a determination that they were considered and that discrepancies with the design package are resolved. In addition, the second level review procedure was mandatory for design change packages prepared by non-licensee engineering organizations and optional for licensee engineering efforts.

The inspectors discussed these issues with the licensee and were informed via a memorandum from the Manager, Design Engineering, dated November 6, 1991, that changes will be made to both NGDP 1203.32 and NGDP 1203.31, "Design Verification", to make the second level review required for all design change packages and require written evaluations for each checklist question that is not considered in a particular technical review. These procedure changes were expected to be completed by December 6, 1991. This LER is closed.

c. <u>(Closed) Licensee Event Report (LER) 90-021 (331/90021-LL):</u> "PCIS Group V Reactor Water Cleanup Isolation Due to Sensed High Heat Exchanger Room Differential Temperature". On December 4, 1990, a reactor water cleanup (RWCU) system ("B" side logic) primary containment isolation system (PCIS Group V) actuation occurred on a sensed high room differential temperature caused by a cold ambient ventilation inlet temperature.

Technical Specification table 3.2-a requires that the reactor cleanup area differential high temperature instruments be set at 14°F above the 100% operation ambient temperature condition as determined by DAEC plant test procedures. The licensee took temperature readings over a three month period and concluded that the 100% operation ambient temperature condition at the plant can vary by as much as 27°F depending on room ventilation conditions, outside air temperatures, and room heat loads. Because of this wide variance, the licensee performed a preliminary study that concluded that adequate RWCU protection is provided with a setpoint as high as 30°F above the maximum 100% operation ambient temperature. Based partly on this study, the licensee selected a setpoint of 50°F which is 9°F above the maximum 100% operation ambient temperature and well within the analytical limit determined by the study. In addition, the licensee is continuing to formalize the study and also work with the BWR Owners Group Leak Detection Improvement Committee to incorporate system improvements based on NRC approved committee recommendations. This LER is closed.

d. <u>(Closed) Licensee Event Report (LER) 91-001 (331/91001-LL):</u> "Manual Scram Shutdown of Plant Due to Steam Leak in the Heater Bay". On January 6, 1991, the reactor was manually scrammed due to an unisolable steam leak on a two inch extraction steam line. This event was described in detail in paragraph 8.a. of inspection report 331/91003(DRP).

The licensee repaired the steam leak by replacing portions of the pipe and adding an expansion loop to the two inch extraction steam line in order to reduce fatigue failure at the weld where the two inch line met the ten inch header. Following completion of repairs, restart of the reactor occurred on January 8, 1991. As discussed in inspection report 331/91015(DRP), paragraph 5., the inspectors will continue to follow the licensee's efforts to monitor and correct wall thinning problems associated with small bore piping. This LER is closed.

e. <u>(Closed) Licensee Event Report (LER) 91-002 (331/91002-LL):</u> "Reactor Coolant Heatup Rate Exceeds Technical Specification Limit Due to Personnel Error". On January 22, 1991, during a reactor startup, the heatup rate for the reactor coolant exceeded 100°F/hour in violation of technical specification 3.6.A.1. This event was described in detail in paragraph 5.a. of inspection report 331/91003(DRP). A non-cited violation was documented in that inspection report for exceeding the technical specification heatup rate.

In order to reduce the likelihood of recurrence, the licensee completed several corrective actions. In addition to disciplining and counseling personnel involved with the error and disseminating information relating to the event to all operating crews, the licensee made changes to two procedures that should enhance operator performance in this area. Operating Instruction (OI) 442, "Circulating Water System", was revised to provide special instructions for startup of the circulating water system during extreme cold weather to minimize freezing and reduce operation's need to rely on reactor water heatup. The revision follows the strategy of diverting circulation water flow from the cooling towers while minimizing dispersion of the flow which passes over the cooling towers. This is accomplished by opening blowdown, bypass sparger, and deicing flow paths, and by utilizing only one riser on one cooling tower. This action was based on the premise that water passing over the tower is less likely to freeze when maintained as a large quantity in one-half of the tower as opposed to being distributed throughout the tower. Surveillance Test Procedure 46A003, "Heatup and Cooldown Rate Log", was also revised to recommend that the heatup rate be maintained less than 25°F per 15 minutes, and to notify the shift supervisor if exceeded. This change should provide ample time for operations to correct an excessive heatup rate prior to exceeding the technical specification.

The above corrective actions appear to have adequately addressed the event. This LER is closed.

f. <u>(Closed) Licensee Event Report (LER) 91-003 (331/91003-LL):</u> "Reactor Scram Due to EHC Oil Fluctuation During Routine Turbine Testing". On February 9, 1991, the reactor automatically scrammed during routine turbine overspeed trip device testing. A detailed description of the event, including its probable cause and licensee's extensive corrective actions, is provided in paragraph 8.b. of inspection report 331/91003(DRP). Following completion of all immediate corrective action, the plant was restarted on February 13, 1991.

One long term action was to calibrate and inspect the electro-hydraulic control (EHC) logic in EHC cabinet IC049 (including associated equipment and ties) every refueling outage. Preventive maintenance action request (PMAR) 91-0253 was prepared to perform this work. This LER is closed.

No violations or deviations were identified in this area.

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 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 core spray 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. Radiological Liquid Spills

During the week of October 14, 1991, three significant liquid waste spills occurred at the plant that resulted in the spread of radioactive contamination in the reactor building. Although no radioactive material was released into the environment, several areas of the reactor building were contaminated, requiring extensive decontamination efforts.

The first spill occurred on October 17, 1991, when operations was attempting to drain clean water from piping associated with the condensate service water system. An operator taped plastic sleeving around a drain line to route the water to a sump drain, and opened the drain line isolation valve. When very little water drained from the line, the operator left the room and opened a vent line associated with the piping to be drained. Opening the vent line allowed the line to drain. However, the plastic sleeving was kinked and water backed up in the sleeving. The sleeving separated from the drain line, spilling the clean water onto contaminated floor areas, causing some flooding into clean areas, and causing the spread of radioactive contamination.

The second spill also occurred on October 17, 1991. To perform maintenance on a pump associated with the chemical waste tank, operators tagged out the valve located between the pump and the tank, drained the tank, and left the tank drain valve open to assure that the tank would not become refilled. The tank drain line discharges to the southwest corner room floor drain which also has a common line to the northeast corner room floor drain. These floor drains, in turn, drain to the reactor building floor drain sump. However, in order for the corner room floor drains to discharge to the reactor building floor drain sump, valve CV-3751 had to be manually opened.

The primary source of fluid to the chemical waste tank comes from the administrative building chemical waste sump. This sump automatically discharges to the tank when it reaches its high level. The sump had been manually drained to the tank at the time of the tagout and was not expected to become refilled during the four hours that maintenance on the pump was expected to take. However, after four days of delay due to lack of parts, the sump filled and automatically discharged to the chemical waste tank. Since the tank's drain valve was tagged open, the discharged fluids were directed to the southwest and, via a common drain line, the northeast corner room floor drains. With the floor drain discharge valve closed, the drains overfilled and spread contamination to the two corner room floors.

The third event occurred on October 18, 1991. Operations had called the radwaste operator to request that the waste collector tank be lined up to receive residual heat removal (RHR) water. After receiving approximately 5000 gallons of water, the radwaste operator contacted the control room and requested that the control room notify the radwaste operator prior to sending additional water to the waste collector tank. The radwaste operator then left the radwaste control center, without securing the waste collector tank, to sample the collector tank prior to processing the tank's water. During the time the radwaste operator was out of the radwaste control center, the control room sent additional RHR water to the collector tank without notifying the radwaste operator. The additional RHR water caused the waste collector tank to overfill resulting in water being directed to the radwaste building equipment sump which overflows to the reactor building floor drain sump. The volume of RHR water was sufficient enough to overflow both of these sumps and flood the reactor core isolation cooling (RCIC) room with about 2 inches of water. This resulted in dose rates of 60 - 80 millirem per hour (near contact) on the RCIC room floor.

These three events have resulted in the licensee issuing Radiological Incident Report (RIR) No. 91-08. The licensee is investigating the events and is performing a root cause analysis and/or review of the RIR. A report will be issued and will include recommended corrective actions. This RIR and root cause report will be reviewed by a regional based radiation protection specialist at a later date.

b. <u>Standby Filter Unit (SFU) Backdraft Dampers</u>

The licensee system engineer for the SFUs determined that discharge dampers D73-002 and D73-003 installed in the A and B SFU trains were not backdraft dampers as they are indicated in the system print. The installed dampers were hand operated balancing dampers which would not prevent backflow as originally intended. Thus, under certain conditions (e.g. loss of control building instrument air and/or loss of solenoid power), an actuation of only one SFU train would have resulted in some portion of that train's air flow recirculating back through the secured train, since the backdraft dampers were not present to prevent backflow. The licensee wrote a nonconformance report (NCR 91-086) to document the problem, and an Operating Order (91-158) to detail actions which operators must take to ensure recirculation flow does not occur. The inspectors reviewed the Operating Order and found discrepancies with the drawing included in it, and with the fact that the actions detailed for the operators did not take into account a failure of electrical power or air not coincident with the SFU start. The inspectors discussed these discrepancies with the Technical Support Supervisor and an Assistant Operations Supervisor and were informed that the operators were given verbal direction to take appropriate action to prevent backflow. The inspectors verified that the operating order could be considered adequate in the short term by interviews with various control room operators. The inspectors questioned whether the system was still considered operable since an automatic function had been replaced by operator action, and whether a 10 CFR 50.59 evaluation had been performed to determine the acceptability of the system in the as-built configuration. The licensee informed the inspectors that an immediate operability call was made, indicating that operator actions were acceptable to allow the system to function as designed. In addition, the licensee agreed to perform a timely operability determination of the as-built configuration. Also, the licensee is planning to perform a special test which will determine the effect of the recirculation flow on SFU system performance. The licensee is also producing a time line history to better understand how the operability questions surrounding the SFU dampers evolved. The inspectors will continue to review the licensee's special test and actions to resolve this discrepancy. This will be followed as unresolved item 331/91016-01 (DRP), pending further review by both the licensee and the NRC.

c. <u>Engineered Safety Feature System Walkdown</u>

The inspectors selected the core spray system for a detailed review based on safety significance of the system, and examined the accessible portions to verify operability of the system. The area around each pump was roped off as contaminated. However, most suction and discharge piping was accessible, including instrumentation. The housekeeping near the pumps was in need of improvement, and there were wood chips in the packing run-off area of the "B" core spray pump. But otherwise, there were no leaks identified and no problems noted with operability of equipment. The system engineer responsible for the housekeeping of the room initiated a request to get the room cleaned and wood chips removed.

The inspectors compared the licensee's system line-up procedure, Operating Instruction (OI) No. 151, "Core Spray System", Revision 11, the as-built drawing, M-121, "Core Spray System," and STP-45A001-Q, "Core Spray System Quarterly and Annual Operability Tests", Revision 10, to ensure procedures matched the as-built configuration. The inspectors noted that several valves were not labelled and this was verified by the system engineer, who initiated a request for labels. All valves and circuit breakers appeared to be in the correct position as indicated by the drawing and procedures.

Several instruments listed in the STP were selected for review, and the calibration records were examined. The inspectors noted inconsistencies in the documentation of recorded data. In several cases, input information, allowable tolerances, and as-left values were recorded as a percent of scale instead of the actual units found on the gage face. Despite the inconsistencies in documentation discussed above, there were no instances noted where the instruments appeared to be out of calibration. At the time of the inspection, the instrument maintenance shop was working on a program to improve record keeping for calibrations. The permanently installed suction pressure gages, PI-2101 and PI-2121, were not included in the calibration program; however, these two gages were not used during the STP and therefore, were not required to be calibrated. Instead, temporary gages were used during the STP that had more appropriate increments for the purposes of the test.

Outstanding maintenance for the core spray system was reviewed to ensure that open CMARs were promptly completed based on safety significance. The inspectors determined that there was no outstanding maintenance that had been inappropriately delayed.

The inspectors concluded that the core spray system was properly lined up, tested, and maintained to ensure operability of the system.

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/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.

Portions of the following maintenance activities were observed/reviewed:

"C" Outboard Main Steam Isolation Valve (CV-4419) packing adjustments

"B" River Water Supply Pump high head impeller installation

"B" Control Building Chiller Well Water Return Isolation Valve (MO2077) overhaul

"B" Control Room Chiller Motor repair

"D" RHRSW Pump and Motor repairs

"B" River Water Supply Pump overhaul

"B" Standby Filter Unit fan motor repair

River Water Dilution Line (CV4909) actuator replacement

Standby Transformer Supply Breaker actuating air tank repair

a. <u>Post Maintenance Testing</u>

On September 30, 1991, the inspectors discussed with the licensee activities that occurred over the previous weekend. Specifically, the inspectors were concerned with the outcome of the Main Steam Isolation Valve (MSIV) Surveillance Test Procedure (STP)-47D004, "Main Steam Isolation Valve Trip/Closure Time Check." This surveillance was being performed to satisfy Technical Specifications 4.7.D.1.b.2, which requires the MSIVs to be tripped individually and closure times to be verified at least once per quarter. The inspectors were informed that due to previous stem galling on the "C" outboard MSIV, a packing adjustment was required to reduce the steam leak. Specifically, the licensee performed the following sequence of actions:

1. Torqued the packing adjustment nuts to 75 ft-lbs
2. Relaxed the torque
3. Retorqued the packing nut to 36 ft-lbs
4. Stroke timed the MSIV

5. Repeated items 1. through 3.

The inspectors questioned the licensee as to why the valve was not stroked following the final packing adjustment. The licensee's position was that it was felt that this activity was not considered a packing adjustment but a retorque of the packing adjustment nuts. Discussions with NRC regional specialists noted that, consistent with previous NRC positions, any adjustment of the valve packing is considered a maintenance activity and, therefore, requires post maintenance testing. This position is based on the potential effect the packing adjustment could have on the valve stroke timing. In reviewing the licensee's Post Maintenance Testing Program Maintenance Directive (MD-024), the inspectors noted that following any packing adjustment of an air or motor operated valve the procedure indicated that post maintenance stroke timing tests should be considered. This directive is intended for guidance for maintenance activities. After further review into the ASME Code, Section IWV-3200, the inspectors noted that the code requires that when a valve has undergone maintenance that could affect its performance, and prior to the time it is returned to service, it shall be tested to demonstrate that the performance parameters which could be affected by the maintenance are within acceptable limits. As a foot note to this section of the code, adjustments of stem packing is considered an example of maintenance that could affect valve performance parameters. The inspectors discussed this concern with the licensee. The licensee subsequently reduced reactor power, performed a successful stroke time test, and returned to full power operation. The failure to perform post maintenance stroke time testing of CV-4419 is considered a Violation (331/91016-02(DRP)) of Technical Specification 4.6.G.2.

b. MO2077 Overhaul

The inspectors noted that the system line-up and tagout to support maintenance on MO2077 was proper; however, the description on the labels for MO2077 valve and operator incorrectly identified MO2077 as "B" control building chiller return isolation instead of "A". MO2078 was also incorrectly labelled and read "A" control building chiller return isolation instead of "B". Even though the improper labelling did not cause any problems with the line-up for the maintenance on MO2077, the potential existed for confusion in the future, and the licensee corrected the labels by the end of the day.

There were a series of delays in the maintenance and testing of MO2077 due to the use of a new procedure and some coordination problems. This was the first time this procedure had been used since a revision, effective July 23, 1991, added steps to balance the torque switch. The electrician missed the steps in the procedure and thought all necessary shop work had been completed, and the valve was re-installed. The electrician later had to remove the torque switch for balancing back in the shop. There was a second delay in the installation of the VOTES sensor required for post maintenance testing. The mechanics had determined prior to the maintenance that due to valve configuration, the normal method of installing a permanent sensor would not be sensitive enough for the test; however, due to coordination problems, this issue was not addressed until after the maintenance was completed and the valve operator was ready for testing. The first time that the VOTES testing was run, the readings were not within allowable tolerances. The maintenance engineer participated in the subsequent performances of the test and satisfactory results were finally obtained.

Despite the delays in the maintenance and testing described above, the inspectors concluded that the maintenance was adequate and was performed by skilled and dedicated mechanics and electricians. Replacement parts were readily available during the overhaul.

c. <u>Equipment Failures</u>

Equipment failures and maintenance problems occurred which took important plant equipment out of service for extended periods of time. Aside from the "B" river water supply pump (mentioned in Section 5), this equipment included the "D" RHRSW pump and motor, the "B" standby filter unit fan and motor, the "B" control room chiller motor, and the standby transformer supply breaker.

The standby transformer provides the alternate power supply to both 4160V vital busses. Thus, when the supply breaker to the transformer (OCB-M) became inoperable due to a leaking air receiver tank, the licensee issued a high priority work order to restore this breaker. The air receiver was badly corroded due to the poor design of its blowdown feature. The warehouse did not have a spare receiver for this breaker and could not readily locate one. Therefore, the licensee was forced to weld repair and hydrotest the existing tank. The inspectors noted that DAEC engineers, welders, and electricians worked diligently to effect quick repairs of this tank and breakers. The inspectors felt that two areas of improvement would have helped significantly in expediting the return of the breaker. Quicker troubleshooting initiation would have possibly saved significant out-of-service time had it been initiated when the receiver was initially found leaking. Having a spare receiver would have saved many days of work and out-of-service time. The licensee has since taken action to make a spare receiver available for the OCB-M breaker.

The "D" RHRSW pump was taken out of service for preventive maintenance, including packing replacement and lower motor bearing replacement. When testing the motor uncoupled after completion of maintenance, the motor exhibited loud bearing noises, and the rotor locked up after power was secured. Troubleshooting revealed that the upper bearing tension was not proper, although it had been set after the lower bearing replacement. The licensee is uncertain as to the exact cause of the improperly set tension. The improper tension allowed the upper end of the motor shaft to wobble excessively and contact the motor housing during the uncoupled run. The licensee determined that no significant damage occurred during this brief period of contact. The maintenance instruction for performing this task gave very little guidance on bearing adjustment, and has been in the process of being revised for some time. In addition, the personnel performing the bearing adjustment of this motor were not the ones normally used to do this type of large motor work. The inspectors will continue to follow the licensee's improvement efforts on large motor maintenance procedures and the use of system experts for key jobs.

The licensee took the "B" standby filter unit (SFU) motor out of service, and entered a seven day SFU Limiting Condition for Operation (LCO) to repair a suspected faulty bearing which was detected by the licensee's vibration trending program. The electricians attempting to pull the motor, discovered that the fan hub had been bound to the motor shaft with a "loc-tite" compound. In trying to break the shaft free of the coupling, the motor end bell was cracked. The licensee did not have a replacement motor available, and was forced to find and dedicate a replacement motor within the scope of the seven day LCO. The licensee also repaired the fan hub set screw holes which had been drilled out to remove the set screws. Although the hub appeared to be oversized, and had possibly been the cause of vibration on the SFU in the past, the licensee chose to reinstall the same fan and attempted to achieve satisfactory alignment and balancing in the present configuration. The balancing did achieve satisfactory results, and the licensee has increased the frequency of vibration monitoring to monthly in order to ensure that fan motor degradation is detected early. The licensee submitted a moderately high priority Engineering Work Request (EWR-890095) in 1989 in order to modify the configuration of the fan and motor assembly. The design of the present assembly is poor in that a small motor shaft is supporting a very heavy blower fan without adequate bearing support. This condition tends to promote the bearing failure, which was seen in this recent failure.

The inspectors were impressed with the level of effort and support that the repair of the SFU received from maintenance, engineering, and procurement. Management involvement to ensure a timely return to service of the equipment was evident. However, much of the work which was performed under the time clock of an LCO could have been accomplished in a controlled manner with ample time for review had EWR-890095 been processed in a timely fashion. The inspectors will continue to monitor the licensee's progress in making permanent repairs to the SFU fan configuration.

The "B" control building chiller developed a loud bearing noise and was removed from service for repairs on October 28, 1991. Electricians disassembled the motor and found arcing damage on both the inboard and outboard journal bearing surfaces. A replacement motor was not available, so the licensee chose to send the motor to a local electric shop to build up the motor shaft with a flame spray process. Licensee electricians reassembled the motor on November 9, 1991, and the motor alignment was being performed at the close of the inspection period.

The licensee had just completed installation of new bearings into the "B" chiller motor in August 1991. Some bearing noise was noticed after the chiller was started up following the August 1991 repairs, but vibration appeared to be within acceptable ranges at the time. A final determination of bearing failure has not yet been made, but would be helpful in determining if the same failure mode still exists in the unit. The licensee suspects that the arcing damage was the primary cause, and it was probably due to welding in the area of the chiller during previous repairs. The licensee is now attempting to procure a spare motor for the control building chillers in order to reduce the down time for similar repairs in the future.

In all these instances the inspectors felt that management, plant, and engineering support was properly focused to resolve the immediate issue in a timely manner. However, proper prior planning, parts support, procedures, engineering support, and training could have prevented some of the failures and the need for extra work in the first place.

Following completion of maintenance on the Standby Transformer and RHRSW systems, the inspectors verified that these systems had been returned to service properly.

One violation and no deviations were identified in this area.

5. <u>Monthly Surveillance Observation (61726)</u>

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-42B016	-	Recirculation Pump DP Monthly Functional Test
STP-45E001-Q	-	RCIC System Quarterly Operability Test
STP-45J002-Q	-	River Water Supply and Screen Wash System Quarterly Vibration Measurement and Operability Test
STP-413B007	-	Fire Water Valve Line-up Check
STP-NS13B001	-	Diesel Fire Pump Engine Overspeed Shutdown and Remote Manual Start Tests

a. <u>"B" River Water Pump Degradation</u>

The "B" river water pump (1P117B) failed to meet its ASME differential pressure (D/P) requirement during surveillance testing on October 9, 1991. The D/P corresponding to rated flow was 20.8 psid which was below the acceptable range of 21.2 to 24.6 psid. The pump had previously been in the alert range for D/P. The licensee had initially scheduled to overhaul the "B" pump in September 1991, but did not meet this milestone. Sending off a spare pump for rebuilding, and upgrading a spare assembly which was in the warehouse received a low priority until the "B" pump D/P dropped into the required action range. The spare pump had recently been sent off for repair and is due back in December 1991. The licensee began working on a rebuild package for the "B" pump after its failure in October. Some parts were not available in the warehouse for installation, including the bowl assembly which was modified to include a high head impeller. Since October 9, 1991, the licensee has had only 3 river water pumps operable, 2 of which are in the ASME alert range for D/P. Had the "D" river water pump, which is in the ASME alert range, fail its ASME testing, the licensee would have been required to enter a 7 day limiting condition for operation (LCO), during which time the pump would have had to be repaired. Repair of these pumps normally takes about two weeks. The inspectors expressed concern that the last two failures of the river water pumps have occurred after the scheduled overhaul deadline for the pumps had been passed. Since repairs made under the added pressure of maintaining system operability or LCO requirements can lead to errors, the inspectors encouraged the licensee to work by the preventive maintenance schedule developed for these pumps, or develop a better schedule, if necessary.

b. RCIC Operability Test

The inspectors observed portions of the quarterly surveillance test for the RCIC system and the restoration of the system to normal service. An LCO was entered for maintenance activities and properly exited following the completion of the STP. The test data was complete and met acceptance criteria.

During the test, there were two instances where delays occurred due to the operator's lack of familiarity with new vibration measuring equipment. In the first instance, the operator in the RCIC room could not get the meter to function properly. While the operators in the control room were trying to locate another meter, the operator realized how to operate the meter. In the second instance, the operator in the RCIC room read the wrong scale on the instrument and originally reported the data to be out of specification until a second assistant, who was familiar with the equipment, obtained the correct data that was within specifications. The licensee indicated that all operators are scheduled for training on the new equipment, which should be completed by February 29, 1992.

The inspectors considered the STP to be satisfactorily conducted in accordance with technical specifications and other requirements.

c. <u>Missed Surveillance Requirements</u>

On October 17, 1991, the licensee discovered that the position of several valves in the Fire Hose Station's flow paths were not being checked monthly as required by technical specifications (TS). Fire header isolation valves V-33-241, V-33-341, V-33-344, V-33-346, and V-33-347, and fire header cross connect valve V-33-342 were not included in the surveillance test procedure (STP) 413B007 (Fire Water Valve Line-up) which is used to verify TS requirements. They were included in the valve line-up for Operating Instruction 513 (Fire Protection System) which is performed during refueling outages, and was last performed on September 3, 1990. These valves were added to the system under a 1985 facility change governed by Design Change Packages (DCP) 1315 and 1316, but were not properly incorporated into the surveillance program as part of the DCP closure or review process.

The inspectors questioned the licensee to see when the last biennial review of STP-413B007 was performed and what was the extent of the review. The licensee informed the inspectors that no formal biennial review was performed on this STP because DAEC procedures still allow the performance of the procedure or any procedure revision to count for a biennial review. The failure to perform comprehensive biennial reviews was discussed with the licensee in July 1990 in inspection report 331/90009. The licensee's test and surveillance supervisor had indicated at that time that the procedure governing biennial reviews, 1406.2 (procedure preparation, review, and approval) would be revised to call for more comprehensive biennial reviews. This was made a licensee commitment control item (091004) in March 1991 with an original due date of July 1991. The procedure revision is still being developed, and the due date has been extended twice to December 1991.

Part of the reason for the delay appears to be the broadened scope of procedures requiring a biennial review in the revision.

The inspectors felt that the discovery of the valves missing from the STP was a good effort resulting from an aggressive followup of a suspected problem. However, several opportunities existed since 1985 to discover the discrepancies resulting from changes made to the facility. Failure to verify the positions of all valves in the flow path to the hose stations is considered a violation (331/91016-03(DRP)) of TS 4.13.2.1.a.

One violation and no deviations were identified in this area.

6. Information Meetings With Local Officials (94600)

During the last few inspection periods, the inspectors contacted local public officials. The purpose of the contact was to provide a line of communication between the local officials and the NRC, and to determine if the officials had any need or interest in a local public meeting to further discuss related community concerns. During the discussion with the officials, no immediate concerns were addressed, nor did the officials express a need for a public meeting. The Senior Resident Inspector informed the officials contacted of the resident inspector program and informed them that the main purpose of the call was to establish a line of communication between the NRC and local officials should future concerns be identified. The officials contacted included: Civil Defense Director, Linn County; Chairman, Board of Supervisors, Linn County; Sheriff, Linn County; Mayor, Cedar Rapids; Mayor, Hiawatha; Mayor, Palo; and Public Safety Commissioner, Cedar Rapids.

7. Cold Weather Preparations (71714)

The inspectors assessed the licensee's implementation of the program for cold weather preparations to ensure that protective measures have been taken to prevent freezing of safety-related process, instrument, and sampling lines during extreme cold weather. The inspectors reviewed the licensee's response to IE Bulletin 79-24, "Frozen Lines" provided by letter dated October 29, 1979, and Integrated Plant Operating Instruction (IPOI) No. 6, "Cold Weather Operations," Revision 5, as well as actions taken to prevent previously identified problems from recurring. The inspectors also toured parts of the plant to verify that protective measures were in place as required.

The program for cold weather preparation includes the use of heat tracing, area heating units, and temperature monitoring of river water, cooling tower basin, demineralized water tank, and condensate storage tanks. IPOI No. 6 is not required to be complete until the ambient temperature remains below the freezing point, and as a result, not all items were complete as of the time of the inspection. Electrical and mechanical maintenance departments kept track of which items were completed using a checklist from IPOI No. 6. Many tasks were also part of the preventive maintenance action request (PMAR) program, coded as a yearly or autumn frequency.

The inspectors found that procedure IPOI No. 6 was not up to date for several changes that had been made to the plant which no longer required winterization steps to be completed. In addition, the electrical shop's list of piping that required verification of proper operation of the heat tracing did not include some required piping, such as well water house piping and off gas radiation sample lines. Heat tracing for the areas listed above has been verified for proper operation. The weaknesses identified in IPOI No. 6 were discussed with licensee personnel, who agreed that the procedure was in need of correction, and initiated a document change form. In addition, IPOI No. 6 is scheduled for a biennial review in November 1991.

The inspectors reviewed licensee actions taken to prevent recurrence of frozen deluge sensing lines for the cooling tower fire protection system as reported in NRC inspection report 50-331/89031. There were no specific actions taken as a result of these problems which occurred in 1989; however, the lines are located in a heated building and there have been no recurrence of problems in the sensing lines.

Despite the problems with IPOI No. 6 as discussed above, the inspectors concluded that the cold weather preparations completed and scheduled to be completed before extreme cold weather conditions are appropriate to meet safety objectives.

No violations or deviations were identified in this area.

8. <u>Regional Requests (92701)</u>

On October 23, 1991, the resident inspectors received a request for information concerning the Duane Arnold containment equipment hatch. This survey is part of a study to evaluate the licensee's ability to secure the containment in a short time period.

The specific information requested in the survey was provided to regional management on October 24, 1991, for further review by NRR to support the NRC's Shutdown Risk Program.

No violations or deviations were identified in this area.

9. <u>Management Meetings (30702)</u>

a. On October 9, 1991, representatives of Iowa Electric and Power Company and the NRC held a management meeting at the Duane Arnold Energy Center. The purpose of the meeting was to discuss items of mutual interest including recent activities, shutdown risk management, procurement, radiation protection enhancements, and the upcoming OSTI inspection. During the meeting, the licensee introduced Mr. Michael Flasch as the new Manager, Design Engineering. Mr. Flasch is on loan from INPO where he previously served as Assistant Manager, Operating Experience Applications Department. Prior to the meeting, Mr. William Forney, Deputy Director, Division of Reactor Projects, and Mr. John Hannon, Director, Project Directorate III-3, toured the facility with the Senior Resident Inspector.

b. On October 11, 1991, a management meeting was held between the representatives of Iowa Electric Light and Power Company and the NRC. The meeting was held at the NRC headquarters office to discuss the licensee's Technical Specification Improvement Program and semi-annual update to the Integrated Plan.

10. <u>Report Review (90713)</u>

During the inspection period, the inspectors reviewed the licensee's Monthly Operating Report for September 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.

11. <u>Unresolved Items</u>

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, violations or deviations. An unresolved item is discussed in Section 3.b.

12. <u>Exit Interview (30703)</u>

The inspectors met with licensee representatives (denoted in

Section 1) on November 1 and November 15, 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.