U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-331/92020(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 1 through October 21, 1992

Inspectors: M. Parker
C. Miller

Approved: R. D. Lanksbury, Chief
Reactor Projects
Section 3B

11/9/92
Date

Inspection Summary

Inspection on September 1 through October 21, 1992
(Report No. 50-331/92020(DRP))

Areas Inspected: Routine, unannounced inspection by the resident inspectors of followup of events, operational safety, maintenance, surveillance, regional request, management meetings, and report review.

Results: An executive summary follows:

EXECUTIVE SUMMARY

Operations

The reactor was operating at about 70 percent power at the start of the period due to problems with hydrogen combustion upstream of the offgas hydrogen recombiners. Reactor power was reduced to less than 10 percent on two occasions in order to eliminate the hydrogen burn, then returned to 100 percent. The licensee reduced power to 60 percent three different times to investigate and repair a steam leak on a moisture separator reheater drain line. These repairs were unable to be completed until a fourth downpower on October 24, 1992, during which time a temporary leak seal clamp was successfully installed. The reactor was operated at or near 100 percent power the remainder of the period except for load following. A notice of violation was issued for failing to follow procedures and poor procedure quality resulting in 1) a temporary loss of the low pressure coolant injection (LPCI) swing bus, and 2) offgas oxygen analyzers being out-of-service and unable to provide control room indication and hydrogen injection trip functions (Sections 2 and 5.a). Inaccurate or inadequate annunciator response procedures were contributing factors to a temporary loss of the LPCl swing bus, and are also cited as an example of procedure violations (Section 5.a). The inspectors raised operability and reportability concerns based on licensee interpretation of Technical Specification (TS) requirements for loss of the LPCI function.

Radiological Controls

Plant chemistry procedures (PCPs) had been identified in need of revision following a 1990 quality assurance audit. Work on the project needed to be increased to meet the December 1992 deadline and to ensure that chemistry and operations responsibilities were well-defined. A drain valve for the offgas oxygen analyzer moisture separator, which should have been shut and capped in accordance with PCP 7.26, was left open and uncapped, allowing room air to be sampled by the analyzers. This contributed to the oxygen analyzers being out-of-service and was considered part of a notice of violation of TS 6.8.1 (Section 2).

Maintenance/Surveillance

Maintenance activities this period were performed well and cleared up some longstanding problems, such as the solenoid valves on the containment hydrogen and oxygen analyzers. Technicians were pursuing an intensive program of motor operated valve overhauls and static and dynamic testing to meet Generic Letter 89-10, "Safety Related Motor Operated Valve Testing and Surveillance," guidelines.

Engineering and Tech Support

A notice of violation was issued for failure to conduct proper inservice testing of valves. Several problems were identified as contributing to this failure, including high personnel turnover rate, excessive reliance on contractors, hard to use software, and inadequate notification practices when equipment requires increased test frequency (Section 5.b). Engineering provided excellent support to troubleshoot and correct offgas system hydrogen combustion.

Safety Assessment/Quality Verification

The team approach, used to address the offgas hydrogen combustion and the loss of LPCI swing bus events, was very effective in identifying root causes and potential solutions. The quality assurance department provided good support in reviewing the inservice testing (IST) program for potential problems.

DETAILS

1. Persons Contacted

R. Anderson, Assistant Operations Supervisor
R. Baldyga, Supervisor, Maintenance Engineering
*R. Becker, Emergency Planning
*B. Bernier, Supervisor, Mechanical Engineering
*P. Bessette, Supervisor, Regulatory Communications
*J. Bjorseth, Assistant Operations Supervisor
D. Boone, Supervisor, Health Physics
*J. Brazant, Electrical Engineering
D. Engelhardt, Security Superintendent
*M. Flasch, Manager, Design Engineering
*J. Franz, Vice President, Nuclear
T. Gordon, Supervisor, Electrical Maintenance
*J. Gushue, Quality Assurance Engineer
*R. Hite, Supervisor, ALARA
*J. Kozman, Configuration Engineering
*J. Loehrlein, Professional Development
M. McDermott, Maintenance Superintendent
*W. McVicker, Foreman, Chemistry
*C. Mick, Operations Supervisor
*T. Page, Nuclear Licensing
K. Peveler, Manager, Corporate Quality Assurance
*J. Probst, Systems Engineering
K. Putnam, Supervisor, Technical Support
*D. Robinson, Nuclear Licensing Specialist
*C. Rushworth, Nuclear Licensing
*P. Serra, Manager, Emergency Preparedness
*S. Shangari, Mechanical Engineering
W. Simmons, Technical Support
*T. Sims, Nuclear Licensing Specialist
*J. Thorsteinson, Assistant Plant Superintendent, Operations Support
*G. Van Middlesworth, Assistant Plant Superintendent, Operations and Maintenance
*D. Wilson, Plant Superintendent, Nuclear
*K. Young, Manager, Nuclear Licensing

U. S. Nuclear Regulatory Commission (NRC)

*C. Miller, Resident Inspector
*M. Parker, Senior Resident 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 October 21, 1992.

2. Followup of Events (93702)

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

September 1, 1992 - Offgas Hydrogen Burn Outside of Recombiners

September 10, 1992 - Loss of Low Pressure Coolant Injection (LPCI) Swing Bus (See Section 5.a)

Offgas Hydrogen Burn

The ruptured instrument air header event of August 31, 1992, caused the offgas system to isolate. After restoring instrument air and the offgas system lineups, operators had difficulty bringing the offgas recombiners into service. On September 1, 1992, the licensee discovered that combustion of hydrogen was occurring outside of the recombiners in the offgas piping upstream of the jet compressor. This was an area with a high concentration of noncondensible gasses enriched by oxygen from the hydrogen water chemistry (HWC) system, and was upstream of steam dilution from the jet compressor. The licensee adjusted system pressure and secured hydrogen injection in an attempt to eliminate the hydrogen burn in the piping. After continued inability to achieve normal recombiner temperatures and review of system parameters with General Electric (GE) technical experts, it was determined that hydrogen combustion had moved further upstream, to the after-condenser of the "B" steam jet air ejector (SJAE). The licensee reduced power to 10 percent to isolate the offgas system while maintaining condenser vacuum with the mechanical vacuum pump. Efforts to extinguish the hydrogen burn in the SJAE after-condenser were initially successful, as evidenced by recombiner temperatures increasing. However, as reactor power was increased, along with initiation of oxygen injection into the offgas system for HWC, the hydrogen burn resumed upstream of the jet compressor and then moved again to the after-condenser of the "B" SJAE.

Further troubleshooting and conversations with GE technical experts led the plant staff to believe that catalyst dust had migrated from the recombiner to points upstream in the offgas system. This dust significantly increased the likelihood of combustion outside of the recombiner. The addition of pure oxygen for HWC further increased the likelihood of combustion. Based on a GE recommendation, the licensee again reduced power to below 10 percent, secured the "B" SJAE while maintaining condenser vacuum using the mechanical vacuum pump, then purged the "B" SJAE with nitrogen. This effort was again successful in stopping the hydrogen burn. Upon increasing power and resuming HWC, the licensee chose not to inject oxygen into the offgas system, but instead decided to inject air into the SJAE after-condenser to ensure sufficient oxygen was available in the offgas system to recombine with excess hydrogen. The offgas system then operated normally until reactor power reached about 95 percent. At that point, operators received an alarm showing 2 percent hydrogen in the offgas system downstream of the recombiners. This condition was indicative of incomplete recombination in the offgas recombiners. By reducing power slightly, operators were able to eliminate the hydrogen concentration downstream of the recombiners.

The high hydrogen concentrations at first appeared anomalous since the offgas oxygen analyzer reading indicated approximately 20 percent oxygen downstream of the recombiners. However, further troubleshooting determined that the oxygen analyzers were improperly lined up, sampling room air rather than the offgas system. This inadequate lineup in effect bypassed the protective HWC trip on low oxygen concentrations (5 percent), which was provided to protect the offgas system from accumulating hydrogen concentrations downstream of the recombiners. At that point, engineers reviewed the temporary air injection rig in the SJAE after-condenser, and determined that the flow regulator chosen allowed less than 1 standard cubic feet per minute (SCFM)[28 liters per minute (LPM)] of air into the system, rather than the 15 to 20 SCFM (424 to 566 LPM) required to ensure full recombination of hydrogen in the recombiners. The licensee then changed air injection locations, this time using instrument air and a 0 to 19 SCFM (0 to 538 LPM) flow regulator to inject air downstream of the jet compressor. This setup allowed the operators to keep adequate oxygen concentrations downstream of the recombiners.

Plant management used an effective team approach to determine the scope of the problem, root cause, and possible solutions. Short term efforts in preventing further hydrogen burns outside of the recombiner have been effective to date. The licensee's long term efforts to prevent offgas hydrogen burns outside of the recombiner were continuing. The licensee's plans were to evaluate modifications which other utilities had implemented, including elimination of the after-condenser, along with possible HWC modifications. Plans to restore oxygen injection into the offgas system were also being evaluated since this would reduce the volume of flow through the system, which would possibly improve the system's effectiveness in reducing nuclide releases.

The inspectors reviewed the problems associated with the improper oxygen analyzer lineup with the licensee and found several problems. Control of the analyzer lineup appeared unclear, with the operations and chemistry departments both having responsibilities for operating the analyzer inlet valve and the moisture separator drain valve. Plant chemistry procedure (PCP) 7.26, "Calibration, Operation, and Maintenance of Orbisphere Oxygen Analyzers," provided chemistry personnel instructions on calibrating the offgas oxygen analyzer and placing it in operation. Operating Instruction (OI) 563, "Hydrogen Water Chemistry System," provided operators instructions on offgas oxygen analyzer startup, shutdown, and valve lineups. Integrated Plant Operating Instruction (IPOI) 2, "Startup," instructed operators to place hydrogen and oxygen injection in service per OI-563. Despite these instructions, the offgas analyzer sample inlet valve (V-89-75) was not opened from the time of the reactor startup on April 24, 1992, until September 2, 1992, when the problem was discovered, despite a calibration performed July 8, 1992, and two startups performed on April 24, 1992, and August 22, 1992. In addition, the moisture separator drain valve (V-89-79) remained open with its drain uncapped even though PCP 7.26 required the valve to be shut and the drain capped. With the sample inlet valve shut and the drain valve open, the offgas oxygen analyzers were sampling ambient air rather than the offgas system. Failure to follow IPOI 2, Step (17); OI-563, Section 3.4; and PCP 7.26, step 7.2.3 is an example of a violation (331/92020-01a(DRP)) of TS 6.8.1, which required applicable areas to have written procedures which are implemented and maintained. The PCPs had been scheduled for rewrite since a 1990 quality assurance audit identified problems in this area. This rewrite had not yet been completed but had a due date for completion by December 31, 1992. The operations and chemistry departments had submitted procedure changes to help correct the problem with oxygen analyzer lineups, and were working on other changes at the close of the period.

One violation and no deviations were identified in this area.

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

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 and/or cleanliness conditions and verified implementation of radiation protection controls. During the inspection, the inspectors walked down the accessible portions of the residential heat removal (RHR) system to verify operability by comparing system lineups 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 TS, 10 CFR, and administrative procedures.

No violations or deviations were identified in this area.

4. Monthly Maintenance Observation (62703)

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

The following items were considered during this review: the limiting conditions for operation (LCO) 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 and/or reviewed:

Offgas System repairs

Hydrogen Oxygen Containment Monitor Solenoid Valve, SV-8117G, coil replacement

River Water System Control Valve, CV-4915, air system repairs

Reactor Core Isolation Cooling (RCIC) Torus Suction Valve, MO-2517, operator overhaul

RCIC Condensate Suction Valve, MO-2500, operator overhaul

Residual Heat Removal Torus Spray and Cooling Supply Header Isolation Valve, MO-2007, torque switch replacement

Core Spray Test Bypass Valve, MO-2112, operator overhaul

Temporary repairs to Moisture Separator Reheater drain line, GBD-56

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

No violations or deviations were identified in this area.

5. Monthly Surveillance Observation (61726)

The inspectors observed TS required surveillance testing and verified that testing was performed in accordance with adequate procedures, that test instrumentation was calibrated, that LCOs were met, that removal and restoration of the affected components were accomplished, that test results conformed with TS and procedure requirements and were reviewed by personnel other than the individual directing the test, and that any deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel.

The inspectors also witnessed portions of the following test activities:

STP-42B015-M - Emergency Core Cooling System (ECCS) Trip System Bus Power Monitors Monthly Functional Test

STP-45E001-Q - RCIC System Quarterly Operability Test

STP-48A001-M - Standby Diesel Generator Monthly Operability Test

SpTP-I76 - MO-2007 Performance Testing in Response to Generic Letter 89-10

a. Loss of Low Pressure Coolant Injection (LPCI) Swing Bus

While performing Surveillance Test Procedure (STP) 42B015, "ECCS Trip System Bus Power Monitors Monthly Functional Test," an operator opened breaker 1D21 Circuit 7 instead of the proper breaker, 1D23 Circuit 7. Breaker 1D21 Circuit 7 supplies control power for breaker 1B4401 which ultimately supplies power to one side of the LPCI swing bus. Sensing a loss of control power to the bus, the swing bus transferred automatically, opening breaker 1B4401 and closing breaker IB3401, deenergizing the bus for approximately 5 seconds. After determining that some procedural guidance in the annunciator response procedures was improper and dispatching an operator to determine actual breaker positions, operators verified that the swing bus transfer had taken place properly. In an attempt to restore the swing bus to its normal lineup, operators opened breaker 1B3401, expecting an automatic transfer of the bus back to 1B4401. Instead, breaker 1B4401 cycled continuously, attempting to close then tripping open, until the operator placed the hand switch in the pull-to-lock position. Operators were then unable to reclose 1B3401 from the control room, leaving the swing bus deenergized. Operators then went locally to 1B4401 and reset the bell alarm lockout, which allowed 1B3401 to close automatically. Following closure of 1B3401, operators were able to restore the swing bus to its normal lineup without further problems.

Upon further review of the issue with the licensee, the inspectors discovered several strengths and weaknesses. Management was involved early and effectively in sorting out the problems that led to the loss of the LPCI swing bus. This involvement included chairing a meeting of the players involved, supporting schedule changes for operators to brief all operating shifts, and implementing some of the recommended changes.

Inattention to detail was an issue in that the operator was given the correct steps to perform by the control room, but operated the wrong breaker. Failure to follow STP-42B015, step 7.2.1, is an example of a violation (331/92010-01b(DRP)) of TS 6.8.1. In addition, poor communications was a potential factor in that the operator was given the order to perform the step over the plant page by using only the procedure step number rather than the verbal description of the action; and no repeat back was given. The licensee had previously implemented programs to address procedural compliance and to enhance operator communications through verbal repeat backs. These programs were not effective in preventing this operator error. Management addressed this issue by emphasizing better communications and attention to detail.

Annunciator response procedure (ARP) errors confused operators and led them to attempt transfer of the bus to an unavailable source. Procedure ARP 1C08B D7, "MCC 1B44A Tie Breaker 1B4401 Trip", listed 1D23 Circuit 7 as a probable cause for the annunciator in several places, whereas 1D21 Circuit 7 should have been listed. This created confusion in the control room until operators used another procedure to verify electrical power. In addition, the ARP guided operators to proceed to bus restoration in accordance with OI 304.2, "4160/480V Essential Electrical Distribution System," without directing them to reset the bell alarm lockout push button. This led operators to attempt the swing bus transfer, resulting in a complete loss of bus power from both 1B3401 and 1B4401 until the suggestions of an astute operator to reset the lockout were carried out. The licensee implemented some ARP procedure changes to correct the specific items mentioned, but was still evaluating general ARP reviews and corrections which might be needed. The licensee's actions in response to previously identified periodic procedure review concerns were ineffective in ensuring the adequacy of ARP 1C08B D7. Inadequately maintained procedures for off-normal conditions is an example of a violation (331/92020-01c(DRP)) of TS 6.8.1.

When the operators unsuccessfully attempted transfer of the swing bus, 1B4401 began cycling or pumping in a succession of attempts to close. This occurred because the bell alarm device provided a mechanical trip but provided no signal to the closing circuit for the breaker in which it was installed to prevent attempted reclosure. This pumping action could be harmful to the breaker and required additional operator action to place the breaker in the pull-to-lock position. In this instance, operator action stopped the pumping well short of the number of cycles for which the breaker was designed. The licensee and the inspectors were conducting further reviews to determine the acceptability of this breaker design. Licensee engineers submitted an engineering work request to evaluate and possibly implement a design change.

Loss of the swing bus resulted in loss of power to all four LPCI injection valves and both trains of the main steam isolation valve leakage control system. Following the loss of the LPCI bus, the inspectors pursued the LPCI swing bus issue with respect to TS operability and reportability per 10 CFR 50.72 and 50.73. In reviewing TS, it was noted that some confusion existed in interpretation of the LPCI subsystem. The licensee's position was that they were in TS LCO 3.5.A.5 with the LPCI bus inoperable. Technical specification section 3.5.A.5 stated "With two RHR (LPCI) pumps inoperable, ... restore at least one RHR (LPCI) pump to operable status within 7 days". However, with the LPCI swing bus inoperable, all RHR pumps were still operable but the LPCI injection valves were in fact inoperable, effectively resulting in the inability of LPCI to physically inject water into the reactor vessel. Thus, the inspectors questioned whether the licensee should have been in TS LCO 3.5.A.6, which stated "Otherwise, be in HOT SHUTDOWN within the next 12 hours and COLD SHUTDOWN within the following 24 hours." Although a plant shutdown was not necessary due to the short duration of time required to identify and correct the problem with the LPCI bus power, it did point to the need for further clarification of TS or better guidance to reactor operators.

In addition, when reviewing the licensee's Emergency Plan Implementing Procedure (EPIP), the inspectors questioned the uniformity of the EPIP with TS. Review of EPIP 1.1, Attachment 2, "Emergency Action Levels," noted that the EPIP required the declaration of an Unusual Event on the initiation of a TS required shutdown for a total loss of the LPCI subsystem. This position did not appear to be supported by the licensee's interpretation of TS.

The licensee agreed to further review this matter with regard to appropriate interpretation of TS and to ensure uniformity of EPIPs with TS.

b. <u>Missed American Society of Mechanical Engineers (ASME) Section XI Required Surveillance</u>

The inspectors reviewed the circumstances surrounding a missed ASME surveillance on the Reactor Core Isolation Cooling (RCIC) pump minimum flow bypass valve (MO-2510). On July 8, 1992, stroke time testing of MO-2510 in conjunction with surveillance test procedure (STP) 45E001-Q, "RCIC System Quarterly Operability Test," revealed that the valve's stroke time had increased to 3.7 seconds from its time of 2.4 seconds on April 26, 1992. This stroke time increase of greater than 50 percent put the valve in the increased frequency testing interval status in accordance with administrative control procedure (ACP) 1407.3, "ASME Section XI Pump and Valve Testing," and Duane Arnold Energy Center (DAEC) inservice testing (IST) program manual. The ACP and ASME Section XI, Article IWV 3417, "Corrective Action," required valves with normal stroke times of less than 10 seconds and which exhibit a stroke time under the maximum allowable value but equal to or greater than 150 percent of the previous stroke time, to be tested at an increased frequency of once each month until corrective action was taken. Despite these requirements, MO-2510 was not tested until August 25, 1992, or 48 days after exceeding the stroke time of the previous test by 150 percent. Other equipment which was listed by the IST program for increased testing initially also appeared to have exceeded its time limits.

However, closer engineering review indicated that this equipment was not required to be on increased testing, because of erroneous initial calculations or because maintenance had been performed on the equipment.

A review of the missed increased frequency surveillance indicated the following programmatic weaknesses:

- Significant turnover in the IST program and reliance on contractors resulted in personnel unfamiliar with program requirements and software. This was exacerbated by the very short notice given to the group that the IST Engineer would be leaving for a training program.

- No backup engineer was designated for IST programs, the requirements of the program were not well-defined, and the software for the system was not user friendly. The IST Engineer position was left vacant for 10 days, then filled by a contractor who was not fully familiar with IST program requirements.

- Notifications to the surveillance and operations groups on equipment to be tested on an increased frequency was conducted by means of a letter put out every 30 days. This left very little time to plan and conduct a surveillance in the case of a valve tested shortly after the previous letter was issued, or in the case of the letter being sent late. The letter in this case should have been issued around July 26, 1992, but was not sent until August 12, 1992.

- The IST evaluation and data entry were not being reviewed for adequacy. The IST Engineer reviewed the STPs, input the data, performed calculations, and established testing windows without any quality checks being performed.

Upon discovery of the missed testing, the licensee comprehensively reviewed the issue to understand the scope and root cause of the failure. An engineering and quality assurance team reviewed the IST program to determine the acceptability of testing for all the equipment in the IST program. This effort led to the discovery that the contractor in charge of the program had introduced several errors into the system. These errors included allowing a

45-day increased testing interval for valves, incorrect leak rate calculations, and failure to remove equipment from increased testing following maintenance. The licensee conservatively tested several valves which appeared to have gone past their required testing interval. The tests yielded acceptable results and showed the equipment to be operable. The licensee also replaced the contractor with one more familiar with the IST program and software and increased the supervisory oversight of the program. An IST Self-Assessment Team was initiated to review the root causes of the breakdown in the IST area and to recommend corrective actions. Some of the findings of this team were included in the programmatic weaknesses listed above. Recommendations made by the team include funding the IST Engineer as a full time position, providing a backup IST Engineer who was familiar with the program, making the IST Engineer a permanent Iowa Electric employee position, fully documenting the program requirements necessary for a smooth turnover, improving IST computer hardware and software support, providing additional guidance and acceptance criteria in ACP 1407.3, improving training, improving communications, and other items. The engineering department's response to the team's recommendations were expected by October 30, 1992. Some of the team's recommendations had already been implemented. Failure to perform increased testing of MO-2510 is a violation (331/92020-02(DRP)) of TS 4.6.G.2.

One violation, two examples of a second violation, and no deviations were identified in this area.

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

On September 11, 1992, the resident inspectors received a request from Region III concerning recent problems identified at other facilities. The three specific issues of concern were 1) a 10 CFR 50.55(e) report on GE 7300 Series breakers, 2) a possible design flaw with vital dc bus arrangements, and 3) emergency diesel generator air start system problems.

These issues have been discussed with the licensee, and they were reviewing them to determine if similar conditions could exist at Duane Arnold. With regard to the 10 CFR 50.55(e) on GE 7300 Series breakers, the inspectors were able to confirm that this series of breakers were not used at the Duane Arnold facility. The inspectors will continue to follow up on the remaining issues.

No violations or deviations were identified in this area.

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

On September 10, 1992, representatives of Iowa Electric Light and Power Company and the NRC held a management meeting at the Duane Arnold Energy

Center. The purpose of the meeting was to discuss recent plant performance, the 1993 capital budget, the average power range monitor bypass issue, control room habitability, the service water system update, and switchyard control.

8. Report Review (90713)

During the inspection period, the inspectors reviewed the licensee's Monthly Operating Reports for August and September 1992. The inspectors confirmed that the information provided met the requirements of TS 6.11.1.C and Regulatory Guide 1.16.

No violations or deviations were identified in this area.

9. Exit Interview (30703)

The inspectors met with licensee representatives (denoted in Section 1) on October 21, 1992, 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.