U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-331/92017(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: July 1 through August 31, 1992

Inspectors: M. Parker
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Section 3C

9/8/92
Date

<u>Inspection Summary</u>

<u>Inspection on July 1 through August 31, 1992 (Report No. 50-331/92017(DRP))</u>
<u>Areas Inspected</u>: Routine, unannounced inspection by resident and region based inspectors of followup; licensee event reports followup; followup of events; operational safety; maintenance; surveillance; plant trips; temporary instruction 2515/115; regional request; concern followup; inservice inspection; and report review.

<u>Results</u>: An executive summary follows:

EXECUTIVE SUMMARY

Operations

The plant was operating at full power at the beginning of the period and maintained full power operations through most of the period. On August 17, 1992, the reactor automatically scrammed from 100% power because of a spurious APRM Flow Biased Upscale trip signal. Following maintenance and corrective actions, the plant was started up on August 22, 1992, and remained at or about full power, except for load following, for most of the remainder of the period. On August 31, 1992, a ruptured solder joint on a three inch instrument air header initiated a transient which left the plant at about 70% power at the end of the period.

Two non-cited violations were documented for exceeding the TS heatup rate of 100°f/hr (Section 3.c) and for failure to complete a fire protection impairment request when required during construction activities (Section 11). An unresolved item was also opened to review the circumstances of operators and fire watches failing to complete actions indicated by plant records (Section 9). Plant walkdowns in normally inaccessible areas revealed generally good condition of the heater bay, steam tunnel, and condenser bay areas. Operator safety and ALARA concerns could be improved by addressing previously identified problems with steam tunnel lighting (Section 5.b).

Maintenance/Surveillance

Two Engineered Safeguards Features (ESF) Actuations resulted from surveillance activities on electrical protection assembly (EPA) breakers (Section 4). Maintenance activities on an instrument air line caused the line to rupture, resulting in a significant plant transient (Section 4). Preventive switchyard maintenance activities resulted in inadvertent tripping of one of two main generator output breakers. The incident did not result in plant or substation transients, but did point out weaknesses in the switchyard testing program (Section 6.a). Forced outage maintenance activities were well coordinated (Section 6.b). The maintenance department implemented test equipment improvements for surveillance activities on differential pressure cells, which should improve the overall reliability of these instruments (Section 7.b).

Engineering and Tech Support

A violation was issued for inadequate design control which led to installation of incompatible breakers into the river water supply system (RWS) breaker cubicles and an eventual breaker fire. Fortuitously, although all four RWS pump breakers were improperly installed, only one was determined to be inoperable, even under postulated seismic events (Section 5.a).

Safety Assessment/Quality Verification

A non-cited violation was written for improper documentation of nonconforming conditions during construction activities (Section 11). The August 17, 1992, reactor scram appears to have a similar root cause to an APRM flow biased upscale scram in 1989. Corrective actions are now underway to minimize the effects of radio frequency interference on plant instrumentation. A repeat steam leak on a three inch, high pressure turbine steam seal line revealed that erosion and corrosion modeling was not in place for this and other piping installed by General Electric, despite previous failures (Section 6.b). Plant reviews of operability and reportability determinations following testing and surveillance activities showed weaknesses. Nuclear Licensing is addressing these areas of concern with activities aimed at issuing detailed guidance on operability determinations (Section 7.a).

DETAILS

1. Persons Contacted

*R. Anderson, Assistant Operations Supervisor
R. Anderson, Senior Outage Project Manager
J. Axline, Technical Support Engineer
R. Baldyga, Supervisor, Maintenance Engineering
*P. Bessette, Supervisor, Regulatory Communications
*J. Bjorseth, Assistant Operations Supervisor
D. Boone, Supervisor, Health Physics
*D. Engelhardt, Security Superintendent
*M. Flasch, Manager, Design Engineering
J. Franz, Vice President Nuclear
T. Gordon, Supervisor, Electrical Maintenance
*J. Gushue, Quality Assurance Engineer
M. Huting, Supervisor, Quality Control
*J. Loehrlein, Professional Development
*M. McDermott, Maintenance Superintendent
*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
*A. Roderick, Supervisor, Testing and Surveillance
*G. Rushworth, Nuclear Licensing
P. Serra, Manager, Emergency Preparedness
*S. Shangari, Mechanical Engineering
N. Sikka, Supervisor, Electrical Engineering
*W. Simmons, Technical Support
*T. Sims, Nuclear Licensing Specialist
*G. Taylor, Environmental
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
B. Bartlett, Senior Resident Inspector
G. O'Dwyer, Reactor Engineer
J. Hopkins, Project Engineer
J. Schapker, Reactor Inspector
J. Smith, Reactor Inspector
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 August 31, 1992.

2. Followup (92701) (92702)

a. (Closed) Violation (331-90023-02): Inoperable Containment Isolation Valve. This violation was a result of the licensee failing to either lock or electrically deactivate the Inboard Torus Vent Isolation Valve, CV-4300, when the Outboard Torus Vent Isolation Valve, CV-4301, was inoperable.

Immediate corrective action consisted of electrically deactivating CV-4300 in the closed position by lifting the power leads to the controlling solenoid valve. The licensee issued a Technical Specification Interpretation as an interim guidance in February 1992 to specify acceptable methods for electrically deactivating valves to satisfy the requirements of TS 3.7.D.2.

Administration Control Procedure 1410.7, revision 0, "Guidelines for Inoperable Primary Containment Isolation Valves (PCIV), was developed to identify PCIVs and penetrations, applicable TS requirements, and the action required when valves were declared inoperable. The procedure identified the valve(s) needed to isolate the containment penetration and the specific circuit breaker or wire lead number and circuit terminal point needed to electrically deactivate the inoperable valve. The inspectors reviewed the licensee's corrective action and have no additional concerns at this time. This violation is closed.

b. (Closed) Violation 331/91003-03: Feedwater Flow Calibration Errors. This violation was issued because the licensee failed to take adequate corrective action to fix inaccuracies with feedwater flow instrumentation which was a primary input to thermal power calculations and subsequently APRM calibrations. Although the licensee had 1988 vendor information highlighting feedwater transmitter inaccuracies, and transmitter calibration records showing a trend of feedwater (FW) flow transmitter drift, the licensee did not take adequate action to compensate for these problems.

The licensee recalibrated the flow transmitters, and on February 15, 1991, plant engineers and maintenance staff devised a method to compare FW flow transmitter (FT) readings with local differential pressure indicators in order to monitor possible drift of FT 1581 and FT 1626. Plant thermal power was then administratively limited first to 98 percent and then to 97 percent as a result of these comparisons. On March 7, the FTs and a power supply for FT 1581 were replaced. On March 11, the plant returned to full power. A letter dated March 29 from Mr. Mineck of IE to Mr. Davis, Regional Administrator, stated that the review of the vendor service bulletin on FW flow inaccuracies and the implementation of recommended corrective actions to the flow transmitters had been completed. The licensee strengthened Nuclear Generation Division Procedure 102.1, "Review of Industry-Related Documents" by stating that when a document such as a General Electric Service Information Letter does not specify a date for completion, the review should be delineated by the Group Leader of Nuclear Licensing, and should not exceed 90 days from the date of receipt. The licensee issued reports to management which identified that status of industry operating experience reviews and any significant time delays in those reviews. The licensee periodically checks the feedwater flow indication by independent indications either locally or by comparing indicated feedwater flow to main turbine first stage pressure. The licensee implemented a plant trending program, with guidance contained in Nuclear Generation Division Procedure 108.2, "Performance Monitoring Program" and ACP 1408.14, "Plant Performance Monitoring and Trending". This violation is closed.

c. <u>(Closed) Unresolved Item 331/91017-02:</u> <u>Failure To Perform A System Operability Determination.</u> This unresolved item dealt with the licensee's performance of a special test to measure the flow in the emergency service water (ESW) system. The flow test indicated that certain safety related components were receiving less flow than was stated in the Updated Final Safety Analysis Report (UFSAR). The NRC identified that the licensee failed to conduct an operability evaluation for the system in the as found condition, but rather waited until an engineering evaluation of the design basis was conducted some months later. This subsequent evaluation found the flow rates to be acceptable.

   The licensee revised procedure 1407.4, "Special Test Procedures" to include a specific line item requiring the test conductor to review test data and acceptance criteria to determine acceptability of results at the completion of the test. In addition, this test was referenced as an NRC commitment. This unresolved item is closed.

d. <u>(Closed) Violation 331/91017-04:</u> Failure To Update Controlled Drawings. This violation was issued due to the licensee's failure to properly update the piping and instrumentation diagrams (P&IDs) to reflect plant field conditions with pipe caps off and hoses installed.

   The licensee's immediate corrective action included reviewing the field configurations identified by the NRC and updating the P&ID to properly reflect the plant status. The licensee's long term corrective actions included a walkdown of portions of the plant to look for any tygon tube attachments. Eleven discrepancies were identified in the areas walked down. The licensee found the safety significance of these discrepancies to be low. DAEC engineers issued Design Document Change (DDC-1954) to correct these discrepancies. DDC-1954 has not yet been implemented and is not currently on the schedule.

Based on the licensee's field walkdown which did not identify any safety discrepancies and an NRC inspector walkdown which did not identify any safety discrepancies, this violation is closed.

e. (Closed) Deviation 50-331/92011-01: Failure To Meet Section 8.2.2.2.5 Of UFSAR Concerning Degraded Voltage At MOV Terminals. The inspectors reviewed the information submitted by the licensee in letter NG-92-3550, dated August 7, 1992, and concluded that the steps taken to analyze and correct the problem were adequate. This item is closed.

f. (Closed) Unresolved Item 50-331/92011-02: Control of MOV Torque Switch Settings In The DAEC Gl 89-10 MOV Program. The inspectors reviewed the information submitted by the licensee with transmittal letter NG-92-3550 dated August 7, 1992, and concluded that (1) the investigation of the root cause of the improperly set torque switches was adequate and (2) the actions taken to correct the problem and to prevent a recurrence were acceptable. This item is closed.

No violations or deviations were identified in this area.

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 actions were accomplished, and corrective actions to prevent recurrence had been accomplished in accordance with technical specifications.

a. (Closed) Licensee Event Report (LER) 90-014 (331/90014-LL): High Pressure Reactor Scram Following MSR High Level Turbine Trip. On September 10, 1990, the main turbine tripped from a sensed high level in the moisture separator reheater (MSR). Reactor power was 27%, or about 2% above bypass valve capacity, so the resulting increase in pressure caused a reactor scram on high pressure. Plant response was normal with engineered safety features operating as expected.

The MSR high level turbine trip logic was "one out of two taken once". One level instrument in the logic was improperly lined up with a manual isolation valve shut, causing condensed steam to slowly fill the sensing chamber, resulting in the high level trip. The isolation valve had been repaired prior to startup from the refueling outage on September 7, 1990. Post maintenance operability testing of the valve was deferred until after the startup, and the pre-startup valve lineups did not include this valve, although it was assumed that it was included.

Short term corrective actions for this event included correcting the MSR level instrument valve lineup, ensuring proper level instrument response, and verifying that all other turbine trip instrument valve lineups were correct. Longer term corrective actions included actions taken to improve valve lineups, and to reduce the likelihood of turbine trips. The licensee initiated extensive walkdowns of plant systems to ensure that root isolation valves were included on piping and instrument diagrams (P&ID) and in appropriate system valve lineups. This work scope was expanded later to include all system valves and coordinated with an effort to provide bar coded labels on all manual valves. The instrumentation effort has been recently completed except for minor problem resolutions. Coordinated plant instrumentation pre-startup valve lineups are now included in Operating Instruction 880, "Non Nuclear Instrumentation", for turbine trip instruments, Group 1 PCIS instruments, and reactor protective system auto scram instruments. The licensee has completed numerous scram reduction modifications since September 1990, including conversion of all turbine trip logic except overspeed to a "two out of three logic," adding PCIS Group 1 solenoid failure detection LEDs, eliminating turbine vibration and exhaust hood high temperature trips, modifying feedwater and condensate logic and air supplies, modifying reactor protection system relays, power supplies, and some logic. The licensee's commitment to ensure prints, procedures, and hardware are upgraded to minimize reactor trips has been evident. This LER is closed.

b. <u>(Closed) Licensee Event Report (LER) 90-015 (331/90015-LL):</u> Manual Scram Following Loss of Air System Pressure Due to Poorly Soldered Joint. On September 13, 1990, with the reactor at about 37 percent power, operations personnel manually scrammed the reactor because of the inability to control reactor water level. The level was increasing because the feedwater regulating valves had "locked up" on a loss of instrument air pressure caused by the failure of an air line's inadequately soldered joint. The initiation of the manual reactor scram and subsequent operator actions were timely and appropriate. All engineered safety features operated satisfactorily as designed.

The licensee's immediate corrective actions consisted of isolating the failed solder joint and placing the alternate instrument air dryer in service. Additional joints were inspected, and two joints were identified with slight leakage. The licensee clamped these joints to ensure they would not suddenly fail. This LER stated that Ultrasonic Test (UT) examinations would be required for soldered joints which are difficult to perform, such as on larger-diameter tubing or in difficult positions. Nuclear Generation Division (NGD) procedure I507.1, "General Brazing/Soldering Standard" was enhanced to require joints two inches in diameter and larger and soldered in certain specified positions to be ultrasonically examined in accordance with UT Procedure 2162.17. UT examination is not code-required for these joints, but has proven very effective in determining the coverage of the solder and the extent of voids in the lap portions of the joint. The corrective actions taken for this LER, although involving considerable UT examinations, were not broad enough to cover other copper piping systems in the plant, such as well water and MSIV nitrogen lines. Following this oversight, a poorly soldered copper joint on a nitrogen supply line to the MSIVs caused an automatic reactor scram on June 22, 1991. LER 91005 documents this scram and eventual corrective actions taken for all soldered copper piping. The review of LER 91005 will discuss these actions. LER 90-015 is closed.

c. <u>(Closed) Licensee Event Report (LER) 90-0I9 (331/90019-LL):</u> Reactor Scrams Following Removal of Potential Transformers. This LER documents a reactor trip on low reactor vessel level. During troubleshooting activities, two electricians inadvertently caused an essential electrical bus to sense an undervoltage condition and initiate a dead bus transfer. When power was restored, three out of four inservice demineralizer beds isolated resulting in a loss of feedwater and the low reactor vessel level. Subsequent to the reactor trip, the sensed undervoltage condition caused another reactor scram on low vessel level. Feedwater was restored to service and vessel level was reestablished.

The licensee's corrective action included:

- Implementing changes to operating procedures and plant equipment to enhance condensate system operation.

- Counseling the electricians involved in the event and providing training on protective relaying to all plant electricians.

- Adding hazard and warning labels to the potential transformer (PT) covers. In addition, a listing of what equipment would be affected when a PT was opened was supplied to the control room.

- Implementing a design change to route a backup supply of power to the optical telephone link.

- Implementing an electrical modification to reduce the electrical load to a breaker which tripped on inrush current.

- Performing an evaluation of the bottom head drain exceeding the heatup rate of 100° F/hour. The actual heatup rate of 150° F/hour was determined to not damage the vessel. As documented in NRC inspection report 331/91003(DRP) the licensee has experienced other violations of the TS heatup rate. In response to those later violations the licensee issued personnel disciplinary actions, administered training to all operating shifts, and evaluated improved methods of monitoring and logging temperatures.

TS 3.6.A.1 states that the average rate of reactor coolant temperature changes during normal heatup shall not exceed 100° F/hour when averaged over a one hour period. Contrary to TS, the heatup rate following the reactor trip was 150° F/hour in the bottom head. This failure to comply with TS requirements is considered a violation. However, in accordance with Section V.G.1 of 10 CFR 2, Appendix C, this violation will not be cited. This LER is closed.

One violation and no 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 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:

July 7, 1992 - Both Emergency Diesel Generators auto started in electrical storm

July 11, 1992 - Loss of Emergency System Notification and normal commercial telephones

July 17, 1992 - Control Building Ventilation in a condition not covered by plant operating and emergency procedures

August 17, 1992 - Reactor Scram due to APRM Flow Biased Upscale Trip Signal (see Section 8. for further details)

August 31, 1992 - Engineered Safety Features Actuation (PCIS Group V RWCU Isolation)

August 31, 1992 - Engineered Safety Features Actuation (PCIS Groups II through V Isolation) due to an RPS EPA breaker trip

August 31, 1992 - Plant Transient and Down Power Evolution due to a decrease in instrument air pressure

On August 31, 1992, with the reactor operating at 100% power, a sudden failure of a three inch instrument air header resulted in a rapid decrease in instrument air header pressure. This decrease in instrument air header pressure resulted in isolation of the service air and non-essential instrument air headers.

The licensee's immediate actions were to identify and possibly isolate the source of the air leak. Operators dispatched to the power block were able to identify and restore the failed copper piping joint with the assistance of mechanics in the area. During this transient, condenser vacuum decreased due to an off gas system isolation, resulting in the operators taking action to reduce reactor power. Reactor power was reduced to approximately 75% to help maintain condenser vacuum.

In reviewing the cause of the piping joint failure, the inspectors noted that mechanics were in the process of removing Belzona material, a metal epoxy compound, from an existing solder joint due to an indication of a leaking solder joint. The application of the Belzona material over existing solder joints was intended to enhance the structural integrity of the existing solder joints, and was initiated to address solder joint failures on copper piping which had previously caused two reactor scrams, on September 13, 1990, and June 22, 1991. The inspectors will continue to follow the licensee's corrective actions. See Section 3.b for additional information on the previous reactor scrams and licensee's corrective actions.

No violations or deviations were identified in this area.

5. <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/cleanliness conditions and verified implementation of radiation protection controls. During the inspection, the inspectors walked down the accessible portions of the high pressure coolant injection (HPCI) 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. River Water Pump Motor Breaker Fire

On June 17, 1992, while attempting to start the "D" river water pump (one of four ultimate heat sink pumps) to verify operability following breaker troubleshooting, the pump tripped and a small fire erupted at the pump breaker cubicle in the intake structure. (See inspection report 50-331/92013(DRP) for further details). New breakers had just been installed the previous week, under Design Change Package (DCP)-1468, to correct breaker coordination concerns. The new breakers are 480 VAC ASEA Brown Boveri K800S, with an SS3 solid state trip unit. The ASEA Brown Boveri K800S breakers were installed to replace a smaller ITE K225 breaker.

Initial followup identified the cause of the "D" breaker failure and fire as attributable to poor contact between the breaker disconnect assembly fingers and the breaker cubicle bus bar stabs. The primary disconnect assembly fingers on the K800S breaker have approximately a 3/8 inch gap versus the K225 breakers 1/8 inch gap. The K225 breaker cubicle stabs which fit into the disconnect assembly fingers are approximately I/4 inch thick. Therefore, the breaker disconnect assemblies on the new solid state breakers were physically larger than those on the old mechanical breakers, and were not compatible with the old bus bar stabs in the breaker cubicle. This poor fit between the disconnect assembly fingers and the bus bar stabs led to arcing and the resultant fire.

Immediately following the initial discovery of the breaker incompatibility, the licensee inspected the remaining three river water system (RWS) pump breakers, and determined a similar condition existed for all four RWS pump breakers. Initial action consisted of replacing the incompatible replacement K800S breakers with the old K225 breakers that had just been removed. Following discovery of improperly sized breaker assemblies installed in the breaker cubicles for the river water pumps, the licensee established a multi-disciplinary task force to determine the root cause of the event, and to recommend corrective actions to preclude recurrence.

While the licensee has performed a comprehensive review into the root cause of the event, the inspectors independently reviewed the circumstances leading up to the incompatible breakers being installed in safety related applications. This review determined that there were several opportunities throughout the design change (breaker upgrade) process to identify and resolve the incompatibility of the ASEA Brown Boveri K800S breaker with the K225 breaker cubicle. Specifically, engineering design, procurement, receipt inspection, installation, and the subsequent troubleshooting process were all potential opportunities to identify and resolve any discrepancies. The breakdown in the licensee's design change process allowed the installation of the incompatible K800S breakers in the K225 breaker cubicle, thus, causing the breaker fire upon initial start of the pump following the breaker installation. This breakdown also resulted in a degradation of the river water system caused by the poor contact that existed between the breaker disconnect assembly fingers and the breaker cubicle stabs for the three remaining river water system pumps. It was fortuitous that the alignment of the breaker finger assemblies with the breaker cubicle stabs was not such that upon initial start of the remaining pump motors, a condition was created similar to the "D" pump breaker fire. The failure to properly evaluate the replacement breaker compatibility with the existing equipment is considered a violation (50-331/92017-01(DRP)) of 10 CFR 50 Appendix B, Criterion III Design Control.

b. Steam Tunnel Inspections

The inspectors accompanied operators on an OP20, "Daily/Week Area Inspection", tour of the heater bay, condenser bay, air ejector room, and steam tunnel. The material condition of the areas was good considering the plant had been operating continuously for over three months. The inspectors observed one EHC oil leak and one minor steam leak, which had both been previously identified by operators.

The inspectors did identify a personnel safety and ALARA concern with steam tunnel lighting. During the inspection, the lights for the steam tunnel area were burned out, leaving the area totally dark. The small hand-held flashlight the operator had been provided did a very poor job of illuminating the area. If a steam leak did exist, this hazard could very easily injure the operator before he saw or heard it. The flashlight also requires the operator to spend more time in the room while he moves closer to each area in order to illuminate it with his small beam. This practice increases total dose accrued on the weekly OP20.

The inspectors discussed this problem with operations, maintenance, and engineering supervision. A Corrective Maintenance Action Request (CMAR), A13052, had been written to replace the bulbs, but the dose acquired in this task was considered too great since the bulb duration was very short. The CMAR was voided to Engineering Work Request (EWR) 920064 to develop a better solution. The EWR had been in place several months and apparently was not working due to funding and some technical resolution problems. The licensee wrote another CMAR to change the steam tunnel lights during a forced outage and began working on a short term solution to provide operators with better steam tunnel lighting.

One violation and no deviations were identified in this area.

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.

Portions of the following maintenance activities were observed/reviewed:

1P22D RHRSW pump "D" terminal bolt retorquing

"B" Reactor Recirculation Motor Generator Set scoop tube control repairs

"G" Switchyard Breaker testing

"A" Control Building Chiller troubleshooting

125 Volt DC Ground troubleshooting

MO-2239, HPCI Outboard Containment Isolation Valve, overhaul

1D10 Battery Bus filter modifications

Reactor Recirculation Flow unit transmitter FT-4631A/C troubleshooting and ferrite "choke" modifications

a. <u>Main Generator Output Breaker Trip</u>

On August 5, 1992, while performing breaker testing in the switchyard, licensee electricians inadvertently tripped open the "H" main generator output breaker, one of two main generator output breakers which also supplies power to the Hiawatha substation. The main generator continued to supply power to the grid through the "I" breaker, and the Hiawatha line remained powered from another source. The breaker trip occurred as DAEC electricians were operating a relay to perform breaker testing on the "G" breaker. DAEC electricians recently took over switchyard breaker testing from other Iowa Electric electricians from the Cedar Rapids operating (CROP) group due to previous problems with breaker trips. The electricians were using generic CROP procedures to perform the testing. DAEC engineers provided the electricians with relays to operate in order to trip the "G" breaker. The contacts of the relay given by the engineer were the right ones to trip the "G" breaker. However, two other contacts on the relay also served to trip the "H" breaker, a fact previously unrecognized by the electricians or the engineer. The inspectors discussed the event with plant management who indicated that future switchyard relay testing would require a plant effects evaluation prior to the test. The licensee is also considering other procedure changes which may be needed to ensure transient free switchyard testing. The electrical maintenance supervisor has been detailed on a special assignment to investigate and coordinate efforts to improve switchyard maintenance practices.

b. Forced Outage Maintenance

Forced outage maintenance activities following the August 17, 1992, reactor scram were well coordinated. Engineering, Operations, and Maintenance combined resources to repair 106 of 131 items on the forced outage work list, including HPCI outboard steam isolation valve, "B" steam packing exhauster, high pressure turbine steam seal line replacement, and general service water piping replacements.

The high pressure steam seal line had been repaired previously but was not included in the licensee's erosion/corrosion program. Since it was piping installed by General Electric, not as much information was available to plant engineers as for other piping installed by Bechtel. Repairs this time consisted of complete replacement of the pipe with chromium molybdenum piping which is much less susceptible to erosion/corrosion damage than the existing carbon steel piping.

Following completion of maintenance on the reactor recirculation motor generator, the inspectors verified that this system had been returned to service properly.

No violations or deviations were identified in this area.

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-4IA008	-	Turbine Control Valve EOC RPT Logic and RPS Instrument Functional Test
STP-42B024-Q	-	RCIC Steam Supply Low Pressure Quarterly Calibration
STP-42B025-Q	-	HPCI Steam Line High DP Instrument Functional Test
STP-45J002-Q	-	River Water Supply System Operability Test
STP-48A001-M	-	Standby Diesel Generators Monthly Operability Test
STP-410A001-CY	-	Control Room Positive Pressure Test
STP-NS13D002	-	CO_2 Cardox System Quarterly Checks

a. Operability and Reportability Concerns

The inspectors reviewed the licensee's followup of two surveillance test procedures (STPs) whose results were initially outside of required values. In both instances the licensee's initial actions led them to operability determinations which later were determined to be non-conservative or inappropriate for the system configuration. In one event, timeliness of corrective actions and determination of operability and reportability were of concern.

(1) Control Room Ventilation

In April 1992 the licensee installed a temporary modification to an exhaust ventilation duct in the cable spreading room. The modification added a ventilation duct and a backdraft damper through the north door of the cable spreading room. The ductwork leads out of the control building, through the administration building, and then outside the second floor of the administration building.

On June 11, 1992, operators performed modified portions of STP-410A001-CY, "Annual Initiation of the Control Room Air Treatment System and Inoperability Test", in order to determine the effect of the temporary modification on control room ventilation. The test showed that with the backdraft damper held opened, control room pressure could not be maintained at the technical specification (TS) required value of 0.1 inches water gauge (wg) positive pressure with one control room filter train operating. Following the test, the licensee postulated that since the duct was not seismically qualified, the duct and normally closed backdraft damper combination may not be available to provide control building envelope integrity. Thus the maximum positive pressure which could be counted upon would be 0.07 inches wg. At the time, the licensee made an initial call that the control building ventilation was operable on the basis that it was uncertain whether or not the ductwork outside the control building would survive in a design basis seismic event, and that 0.07 inch wg positive pressure should be sufficient to maintain control room habitability. The licensee documented the condition in a non-conformance report on June 15, 1992.

On July 10, 1992, approximately one month following the test, licensee engineers concluded that there was insufficient information to determine that the temporary ductwork would be intact in a design basis seismic event. The Operations Committee (OC) met on July 14, 1992, and reviewed the details of the nonconformance report which was written June 15, 1992. The OC determined that procedure changes may be necessary to ensure that control building ventilation would remain operable, and set an agenda item to review the matter further. As a result of the OC discussion, the licensee initiated temporary changes to Abnormal Operating Procedure 901, "Earthquake", and the annunciator response procedure for the "control building intake radiation monitor trouble" annunciator to provide assurance of control room habitability during a seismic event, but no time for completion of the procedure changes or operator training on them was given.

The licensee briefed the inspectors about the failed surveillance and the licensee's action taken to date on July 17, 1992. At that time, the inspectors discovered that the licensee had not revised their operability call based on the seismic review completed on July 14, 1992, had not reported degradation of the system in accordance with 10 CFR 50.72, and had not taken sufficient actions to ensure that the appropriate procedure changes were in place and understood by plant operators in the 24 hour time frame of the action statement for Main Control Room Ventilation TS 3.10.1.3.a. The inspectors also noted that the plant effects evaluation performed for the temporary modification and subsequent extended temporary modification lacked detail, especially involving seismic concerns. The inspectors discussed these problems with the licensee and Region III. The licensee then made the determination that the event was reportable under 10 CFR 50.72 and 50.73, and made the appropriate notification. The DAEC staff verified the operability of the system on a short term basis by ensuring that the procedure changes recommended at the previous OC were completed, implemented, and reviewed with control room operators. The inspectors verified that sufficient details were considered in the plant effects evaluation even though they were not documented in the temporary modification package. Licensee engineers are still developing design change package (DCP) I511 which will ensure the necessary duct work and dampers will survive in a seismic event.

The licensee suspects that leaks in the standby filter unit trains may be slowly degrading system performance. Previous tests performed prior to the temporary duct installation have shown the SFUs able to supply 0.11 inch wg pressure at 1000 SCFM flow with the cable spreading room door open. The same test performed on June 11, 1992, showed the SFUs to only be able to supply 0.06 inch wg pressure at 1000 SCFM flow with the cable spreading room door open. As of the close of the period, the licensee has not initiated comprehensive walk downs to locate and seal leaks in the system.

(2) <u>"B" River Water Pump Vibrations</u>

On July 7, 1992, while performing Surveillance Test Procedure (STP) 45J002-Q, "River Water Supply System Operability Test", the licensee declared the "B" River Water Supply (RWS) pump inoperable due to exceeding its ASME vibration limit. Since the "D" RWS pump was already inoperable due to a breaker fire, this made the "B" loop of RWS system inoperable. The licensee appropriately entered the seven day LCO for an inoperable RWS loop.

Licensee engineers evaluated the vibration increase in the "B" pump to determine the scope of the problem. Baseline data for the "B" pump motor showed .6 mils displacement for point 1 and .7 mils for point 2. Vibration readings on July 7 showed 0.29 mils displacement at point 1 and 2.1 mils at point 2. This is compared to the ASME maximum allowable values of 1.8 and 2.1 mils respectively. The licensee sent divers to the intake structure and found that sediment levels were high (approximately five feet of accumulated silt). Although the "B" pump had been in the alert range for increasing vibration for some time previous to July 7, licensee engineers postulated that heavy local rains had suddenly increased sediment in the intake structure, which was responsible for the increased vibration of the "B" pump. Based on that postulation, documented in a July 9, 1992, letter, "NG-92-3210", from the Manager of Engineering to the Plant Superintendent, the licensee declared the "B" pump operable on July 10, 1992. The position stated in the letter was that no real pump degradation had occurred, and that the reference value should be revised in accordance with paragraph IWP-3112 of Section XI of the ASME code.

The inspectors expressed concern that revising the reference values, although allowed by paragraph IWP-3230 (vice IWP-3112) of the code, should be done with proper prior evaluation and caution. This is because increasing the reference value when a real problem exists actually masks the problem, allowing it to exist for a longer period prior to reaching alert and action required levels. The inspectors also pointed out that the paragraph IWP-3112, referenced in letter NG-92-3210, allowed an additional set of reference values to be added for certain conditions but not a revision of existing reference values.

On July 11, 1992, the licensee pumped the silt from the intake structure pits and reperformed STP-45J002. The results showed that the vibrations were still high, even after the pits were pumped. The licensee then declared "B" RWS pump inoperable again, and re-entered the original LCO in day four of seven. On July 12, 1992, after balancing the motor on the "B" RWS pump, the licensee completed STP-45J002 successfully. The vibration readings of 1.6 mils displacement for point 1 and 0.975 mils for point 2 still leave the pump in the alert range, but are lower than the required action range. The licensee again declared the "B" RWS pump operable, and left it on an increased surveillance frequency of 45 days. The licensee later determined through further vibration analysis that the operating condition of the pump has changed significantly, that misalignment is probable and that impeller rubbing is possible. Although the pump condition is not degraded enough to be inoperable, its condition does call for close monitoring, as was the intent of the ASME program.

The licensee agreed that the reference value for the pumps should not be changed. In addition, licensee engineers have recently created a trending file for the RWS pumps since they have historically had vibration problems.

(3) Conclusion

These two events point to the need for increased oversight of engineering evaluations, especially in regard to plant operability and event reportability. The use of a critical questioning approach must be emphasized. The licensee intends to issue DAEC specific guidance on operability reporting, based on Generic Letter 91-18, "Information To Licensees Regarding Two NRC Inspection Manual Sections On Resolution Of Degraded And Nonconforming Conditions And On Operability". The inspectors will continue to closely monitor the licensee's efforts in this area.

b. Surveillance Program Improvements

While observing performance of STP-B025-Q, "HPCI Steam Line High DP Functional Test", the inspectors noted the technicians' increased proficiency in use of the wet leg calibrator. The calibrator is a new device to DAEC which maintains fluid fill in differential pressure instrument lines during calibration. Proficient use of this device, such as was observed, should help ensure that instrument error due to residual gas bubbles is minimized.

The inspectors have noted several recent examples where instrument trending reviews have benefitted overall reliability at DAEC. Instruments such as PDIS-4641 and 4642, "LPCI loop select differential pressure indicating switches", were trended long enough to establish a history of poor performance, then put on an increased surveillance frequency to ensure proper operation while awaiting replacement instruments.

No violations or deviations were identified in this area.

8. Plant Trips (93702)

Following the plant trip on August 17, 1992, 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.

On August 17, 1992, the reactor automatically scrammed on an APRM Flow Biased Upscale trip signal. All engineered safety features responded as expected following the reactor scram, including PCIS Groups II through V isolations, resulting from the reactor vessel level shrink.

The licensee proceeded to cold shutdown to accomplish necessary repairs and to perform additional forced outage activities and to determine the actual cause of the scram. Major activities included repair of MO-2239, HPCI outboard steam line isolation valve, replacement of high pressure turbine seal leak off line due to a steam leak caused by wall thinning, and general service water header piping replacement due to wall thinning.

The post scram review indicated that actual neutron flux did not rise, but that the scram was actually initiated due to lowering of the APRM flow biased scram setpoint. Review of plant transient data showed that indicated recirculation loop flow for the affected instruments spiked in the downward direction, lowering the flow bias scram setpoint below actual power level (100%). The instruments involved are located in the NE corner room and have been previously found to be susceptible to high frequency interference signals, causing a reactor scram in 1989 due to radio communications in the corner room. While the licensee has not determined the actual source of the interference, they have taken extensive action to reduce the impact of high frequency interference signals. These actions include installation of a ferrite "choke" device near the affected flow transmitters which has significantly reduced the instrument susceptibility to signal fluctuations caused by external high frequency noise sources.

The licensee commenced a reactor startup on August 22, 1992. The reactor was declared critical, with a 150 second period. This concluded a six day forced outage following the reactor scram.

No violations or deviations were identified in this area.

9. Temporary Instruction 2515/115

(Closed) Temporary Instruction (TI) 2515/115, "Verification of Plant Records." This TI was issued to determine if practices of individuals performing surveillances and log entries are such that there is a potential for falsification to occur. The inspectors discussed with the licensee the extent of self monitoring performed which would allow them to detect falsifications. On June 18, 1992, the licensee's Quality Assurance department had completed a surveillance of operating logs of nuclear station auxiliary operators and second assistant nuclear station operating engineers, comparing their log entries for actions taken in vital areas to security computer records. The surveillance was initially broad in scope, covering 80 different eight hour watches for sixteen individuals. When certain individuals' logs showed discrepancies with the computer tracking, the surveillance was broadened to look at more of these individuals' logs in other time periods, and at certain vital areas in greater depth. With these additions, the surveillance covered a time period of about October 1991 until April 1992.

Results of the surveillance indicated no log entry discrepancies for the majority of individuals. Two individuals, however, had numerous discrepancies. The licensee took the following corrective actions as a result of these discrepancies. Operations Department Instruction 13, "Auxiliary and Second Assistant Operator Logs", was changed to ensure that management expectations for log taking are clarified, and to provide a means to document incomplete rounds. The operations supervisor sent a letter to all operators to inform them of the changes, and to emphasize the need for complete and accurate logs. The licensee took disciplinary action for the two individuals with discrepancies. The licensee reviewed the discrepancies, and determined that plant safety was not compromised and no technical specification (TS) required actions were missed.

Due to industry events, the licensee next decided to perform a surveillance on hourly fire watches required by TS or other commitments. Quality Assurance performed this surveillance, starting about July 13, 1992, with a goal of verifying via security computer records that appropriate room entries were made to support fire watches for all Fire Protection Impairment Requests (FPIR) in place on the week of June 8, 1992. The majority of the fire watches required were performed by the licensee's "outage fire watch" round performed by security guards. This round checks 42 areas in a one hour period, 20 of which can be monitored by the security computer. Of the 3360 watches checked by the surveillance, 48 discrepancies were noted. Interviews with the fire watch personnel indicated that most of the problems arose over confusion as to what areas to cover. A single form covering one week's worth of watches was used to document the activity; and one set of initials represented an individual performing the fire watch in 42 areas. This left it up to the individual's memory to cover all 42 areas. Adding to the confusion was the fact that actual requirements for the outage fire watch changed from time to time, and some fire watches took the initiative not to cover an area if it was not required by a FPIR.

Of the 48 unlogged discrepancies, the licensee initially determined that only one missed fire watch on "B" Emergency Diesel Generator was required by TS. A subsequent engineering evaluation determined that even this area did not require a fire watch. The other missed areas were required only by plant procedures or were covered by fire watches in rooms adjacent to where the fire watches should have been posted.

The licensee has taken short term corrective action by requiring the fire watches to cover all areas of the "outage fire watch" whether or not they are required by a FPIR. The "outage fire watch" form has also been revised to allow a check off for each area covered to aid the fire watches in remembering which room to check.

The licensee plans to perform at least two more surveillances before the end of 1992 to monitor operator rounds, fire watches, and possibly maintenance or other activities which could be recorded by the security computer. The results of these surveillances will be used to determine the need for, and frequency of, future surveillances of this type. The inspectors will continue to review the results of these surveillances.

Failure to perform operator checks and fire watches appears to be an issue of procedural non-compliance. Pending further NRC review into this industry wide problem, this will be followed as an unresolved item (331/92017-02(DRP)). This temporary instruction is closed.

No violations or deviations were identified in this area.

10. Regional Requests (92701)

a. Plant Information Books

The inspectors responded to a Region III request to provide simplified plant diagrams for incorporation into a DAEC plant information book. Plant information books are being prepared for all sites as a standardized reference source for NRC use in emergency response, reactive inspections (such as AIT), and other briefing opportunities. Nuclear Licensing responded quickly to the inspectors' request for simplified drawings. The material provided went beyond the quality and quantity of information requested. The material has been sent to Region III for incorporation into the plant information book.

b. Spent Fuel Pool Survey

The inspectors acted on a Region III request to review storage practices of tools and material located in the spent fuel pool (SFP). The concern initiating the request resulted from a September 12, 1991, event at another facility in which a jet pump stored in the SFP fell in the vicinity of spent fuel after a cable suspending it corroded and broke.

DAEC procedure 1407.2, "Material Control in the Spent Fuel Pool and Cask Pool", identified requirements and methods of storage and documentation of non-fuel material in the SFP and cask pool (CP). The inspectors accompanied licensee engineers during an inventory of the pool and noted that items except tools were controlled, and that the inventory sheets and tags were up to date. One item, a pump, was being temporarily stored in the SFP using nylon rope rather than the stainless steel cable required by procedure 1407.2. The licensee resuspended the pump and another tool, which had been taped to the SFP railing, using stainless steel cables.

These items and other fuel handling tools are usually stored in the CP, which is adjacent to and normally separated from the SFP by a water tight gate. The licensee is presently engaged in a spent fuel pool cleanup project which will cut and ship 36 control rod blades, an LPRM, and other assorted items. The expected final shipping date is early September. The tools and other objects will then be moved back to the CP such that no heavy objects will be suspended in the SFP.

c. Emergency Diesel Generator Unavailability

The inspectors collected data on emergency diesel generator (EDG) unavailability in response to an NRR request. The total number of hours of down time during which the "A" and "B" EDGs were required to be operable was tabulated for the period June 1990 to May 1992. DAEC EDG unavailability as of January 1, 1992, was approximately 0.90%, and as of July 1, 1992, it was 0.34%, considering the EDG systems themselves and not support systems such as essential service water. This information will be used to support a review of changes proposed to the Station Blackout Rule.

11. Concern Followup (37702)

(Closed) AMS RIII-92-A-030: On March 17, 1992, an individual brought to the NRC ten concerns. The aspects of these concerns that were substantiated had little to no safety significance. These concerns and their dispositions are discussed individually below.

Concern no. 1.: On March 17, 1992, the individual brought a security concern to the NRC. The results of the inspection were documented in NRC Safeguards inspection report 50-331/92012(DRSS).

Concern no. 2.: The individual asserted that on January 21, 1992, work was started on the "B" well water system prior to the work package being signed, or any briefing of the crew.

Conclusion: This concern was partially substantiated. It should be noted that the well water system is a non-safety-related system.

Details: The licensee stated that during a job briefing it was noticed that the Field Engineer's signature on the job traveler was missing. This signature verifies that all the required signoffs had been obtained. The licensee stated that personnel checked at that time and found that all required signoffs had been obtained. The Field Engineer's signature was then obtained before proceeding with the work.

Concern no. 3: The individual asserted that on January 21, 1992, a load of tools was taken offsite and when the Health Physics technician checked the load he did not open the ends of the 4 inch conduits and check inside. This concern was not substantiated. An inspection determined that the licensee's contamination control procedures appeared to be implemented properly. Further discussion of this concern was documented in Paragraph 11 of NRC inspection report 50-331/92016(DRSS).

Concern No. 4: The individual asserted that he requested training on how to work from the work package and on how to use the traveler. The individual asserted that no training was given and that he was told no class would be given to craft people during this outage.

Conclusion: This concern was not substantiated. However, sufficient training appeared to have been given.

Details: The licensee stated that classroom training was not a prerequisite for craft workers, that trained people were supervising the work, and craft workers were to learn by on-the-job-training. The individual had received Outage Workers Procedure Course on February 4, 1992, and three Electrical Construction Procedures classes on January 29, 1992. These classes provided training on checklists, travelers, cables, raceways, and terminations.

Concern No. 5: The individual asserted that on January 29, 1992, after he was briefed on the work package for thermal overload monitors in safety-related Motor Control Centers (MCC), he asked for a class on terminating. He was told by supervisors that there would be no class due to the short outage. The individual asserted that on February 6, 1992, after four days of terminating on a safety-related system, he finally got to see the terminations procedure.

Conclusion: This concern was not substantiated. The safety-related terminations appeared to have been accomplished properly.

Details: The work being referred to was DCP 1482, which was safety-related work but not "Environmental Qualifications" (EQ) work. The licensee stated that the individual was an experienced journeyman electrician, received the classroom training as discussed in concern no. 4 above, received EQ termination training while working at DAEC in 1990 outage, did not receive EQ training during 1992 outage because this was not EQ work, and had a pre-job briefing with the foreman and field engineer, both of whom are journeyman electricians. The licensee stated that the work traveler provided the procedure, the field engineer inspected the work in the shop, and QC personnel inspected the work after installation. The licensee stated that the terminations procedure applicable to the DCP was included in training given to the individual and was part of the work package.

Concern No. 6: The individual asserted that a supervisor ordered an Iowa Electric (IE) laborer to open penetration N203 from the cable spreading room to the turbine building without a Fire Protection Impairment Request (FPIR).

Conclusion: This concern was partially substantiated in that a FPIR was not generated in a timely manner. However, no fire hazard or safety significant problem resulted since a fire watch was stationed in the area for other reasons.

Details: The IE Administrative Procedures require that when a penetration is opened, a FPIR be completed to document whether or not a fire watch is needed. A continuous fire watch had already been established as required by Technical Specifications (TS) because the cable spreading room door was open. A FPIR was generated when IE fire protection personnel realized that one had not been completed for penetration N203. The FPIR documented that a fire watch was not needed because "fire pillows" were being installed in the penetration when it was left unattended. The project engineer was reminded about the need for an FPIR even under those circumstances.

The failure to complete a FPIR when required is considered a violation of DAEC Administrative Procedure 1412.4, "Planned Impairments to Fire Protection Systems", as required by Technical Specification 6.8.1. No notice of violation will be issued because the violation meets the criteria specified in section V.G. of 10 CFR Part 2, Appendix C, in that: a.) it was identified by the licensee, b.) it is classified as a Severity Level V violation, c.) it was not reportable because it did not result in plant operation that was prohibited by Technical Specifications since no fire watch was needed, d.) it was corrected with measures to prevent recurrence within a reasonable time period, and e.) it was not a willful violation.

Concern no. 7: The individual asserted that personnel prefabricated jumpers on DCP-1482, recorded no crimp numbers in the package, and jumpers were later installed by night shift.

Conclusion: This concern was substantiated. However, there was no safety significance and no requirements were violated.

Details: The licensee acknowledged that some jumpers were prefabricated including crimping without the crimp numbers being recorded in the Design Change Package. The licensee stated that the DCP documentation was not available at the time, so the crimper number and calibration due date were written down separately and transferred later to the DCP. The foreman and engineering approved this so that prefabrication work could proceed until the DCP was available. QC personnel inspected the wires, lugs, and crimps in the field during installation.

Concern no. 8: The individual asserted that on February 24, 1992, nine wire pull packages were violated when a cable pull was started without proper approval, resulting in a deviation report.

Conclusion: The concern was partially substantiated. However, the work was accomplished correctly because IE personnel identified and corrected the administrative omission. No safety significant problems had been caused.

Details: The licensee stated that nine construction packages containing cable pulls for non-safety related DCP 1519, were started without the Operations Supervisor review and the Operations Shift Supervisor release for work as required by Administrative Control Procedure 1403.2. This work was stopped when the construction engineer noticed the omission. Refresher training on requirements was conducted with all construction engineers, field engineers, superintendents, foremen, general foremen, and QC personnel. The licensee stated that all ongoing work was verified to be in compliance, Operations personnel were aware of the work in progress, the cable spreading room was tagged out to support the cable pulls, and all required signatures were obtained before work was restarted the next evening after meetings were held with the craft personnel. Deviation Report 92-59 was initiated by licensee personnel to provide a mechanism for thorough evaluation, root cause determination, and corrective actions to prevent recurrence of this type of error.

Concern no. 9: Individual asserted that window clamps were installed as conduit supports instead of the beam clamps required by Design Change Package 1524-06, they were installed backwards and signed off by a worker and a quality control (QC) inspector. The individual further asserted that the window clamps had been removed and corrected to beam clamps without paperwork after another QC inspector threatened to write a Nonconformance Report (NCR).

Conclusion: This concern was partially substantiated however the work had been accomplished correctly.

Details: DAEC Quality Assurance procedure 1111.I, Rev. 5, "QC Inspection Process", Attachment 2, "high consideration inspection activities" required that divisional raceway supports (such as the conduit supports in the concern) be inspected by QC inspectors. A craft worker and a QC inspector initialed (or "signed off") the conduit supports as installed on March 3, 1992. DAEC Quality Assurance Manual, Chapter 12 "Nonconformances" step 12.4.1 stated that all personnel were responsible for reporting items which may be nonconforming to the Corporate QA department which will issue a NCR. Another QC inspector informed the NRC inspector that he had documented the improper beam clamps on a General Inspection Report (GIR) dated March 14, had not formally issued the GIR, and had filed it informally in the possession of the Dayshift Construction (DC) Supervisor. The QC Supervisor informed the NRC inspector and the QC inspector that the QC inspector should have issued the GIR on March 14, and it would have satisfied the requirement for formal documentation of non-conforming items. He also indicated that the changing of items that individuals, particularly QC inspectors, have signed off as verified must be documented by appropriate methods. The QC Supervisor had the GIR issued as GIR E-92-001 and provided copies of the unissued and the issued GIR to the NRC inspector. The lack of formal documentation was a violation of QA Manual step 12.4.I and a violation of Criterion V of Appendix B of 10 CFR Part 50. No notice of violation will be issued because the violation meets the criteria specified in section VII.B.1 of 10 CFR Part 2, Appendix C, in that it was an isolated violation and the licensee initiated appropriate corrective actions before the inspection ended. There was no safety significance to this lack of formal documentation because installations met QC requirements even though they were not documented in a formal manner.

Concern no. 10: The individual asserted that on March 16, 1992, incorrect cables were pulled in conduit for DCP-1519 after being approved by warehouse, QC, and a foreman on night shift, and were to be changed on March 17, 1992.

Conclusion: No safety significant problems had been caused and the work had been done correctly.

Details: The concern was not substantiated because in a followup telephone conversation between the individual and the inspector, the individual explained that: 1) no requirements had been violated, 2) IE personnel identified and corrected the work, 3) the work had been ultimately done correctly, and 4) he reported this to the NRC because he was frustrated that the work had been done incorrectly at first.

There were no safety concerns and two non-cited violations identified in this area.

12. Review of Inservice Inspection (ISI) Summary Report (73051)

The NRC inspection of the ISI activities at the Duane Arnold Energy Center is documented in NRC Inspection Report No. 50-331/92004 (DRS). The NRC specialist inspector reviewed the 1992 Refueling Outage ISI Summary Report of activities performed from September 11, 1990 through April 27, 1992 and determined that the observations made by the NRC inspector during the above inspection are consistent with the data presented in the ISI summary report.

13. Report Review (90713)

During the inspection period, the inspectors reviewed the licensee's Monthly Operating Report for June and July, 1992. 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.

14. Unresolved Items

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 disclosed during the inspection is discussed in Section 9.

15. Non-Cited Violations (NCV)

During this inspection, certain of your activities, as described above, in paragraphs 3.e and 11 appeared to be in violation of NRC requirements. However, the violations were either categorized at Severity Level IV or V and they are not being cited because the criteria specified in Section V.A and V.G of the "General Statement of Policy and Procedure for NRC Enforcement Actions," (Enforcement Policy, 10 CFR Part 2, Appendix C, (1992), were satisfied.

16. Exit Interview (30703)

The inspectors met with licensee representatives (denoted in Section 1) on August 31, 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.