U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-331/90009(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: May 16 through June 27, 1990

Inspectors: M. Parker
C. Miller
C. Phillips

Approved: R. L. Hague, Chief
Reactor Projects Section 3C

7/13/90
Date

Inspection Summary

Inspection on May 16 through June 27, 1990 (Report No. 50-331/90009(DRP))
Areas Inspected: Routine, unannounced inspection by the resident inspectors and a regional based inspector of followup; followup of events; licensee event report followup; operational safety; maintenance; surveillance; temporary instruction (SIMS I.C.1.2.B, I.C.1.3.B, II.F.2.4, II.K.3.57 closed); management meetings; and report review.
Results: The unit was operating at 83% power at the beginning of the period. The licensee reduced power for routine surveillance, and load following. Reactor power has been limited to 83% power due to an inoperable MSIV, requiring continued operation on three main steam lines. On May 21, 1990, a reactor runback, caused by an instrument bus temporary under voltage condition, was manually terminated at 75% power. On June 17, 1990, operators manually ran back power to about 60% in order to maintain condenser vacuum after rain water leaked onto "B" circulating water pump, which tripped on a ground overcurrent condition. On June 21, 1990, the licensee discovered that MOV 1989 ("B" RHR Torus Suction Isolation) was inoperable in the open position. After discussions with NRR and Region III, the licensee determined that the "B" RHR system was operable with the valve opened, and that its containment isolation function could be performed, if needed, by the RHR pump suction valves. An open item was assigned to further review containment integrity issues (section 5b). During the period, the licensee discovered a leaking

Control Rod Drive (CRD) withdraw line. An open item was assigned to further evaluate the failure mechanism and repair (section 3b). Drywell unidentified leakage increased to about two and one-half gpm, then decreased to about 0.8 gpm during the period (section 3a). APRM flow biased scram and rod block setpoints were found to be set nonconservatively high due to changing recirculation flow requirements and procedural problems (section 3d). One unresolved item was issued to review the DAEC biennial procedure review program (section 3d). Refueling preparations, including fuel and channel receipt inspections, continued throughout the period with no major problems encountered.

DETAILS

1. Persons Contacted

*R. Anderson, Testing and Surveillance Supervisor
R. Anderson, Assistant Operations Supervisor
P. Bessette, Senior Licensing Engineer
J. Bjorseth, Maintenance Engineering Supervisor
A. Browning, Acting Manager, Nuclear Licensing
*V. Crew, Technical Support Engineer
D. Englehardt, Security Supervisor
D. Fowler, Operations Shift Supervisor
H. Giorgio, Radiation Protection Supervisor
*R. Hannen, Plant Superintendent, Nuclear
M. Huting, Quality Control Supervisor
D. Kerr, Fire Marshal
B. Lacy, Manager, Design Engineering
R. McGee, Technical Support Engineer
*C. Mick, Operations Supervisor
W. Miller, Supervising Engineer, Analysis Engineering
N. Petersen, Senior Licensing Engineer
*K. Peveler, Corporate Quality Assurance Manager
J. Probst, Technical Support Engineer
*K. Putnam, Technical Support Supervisor
*R. Salmon, Technical Services Superintendent
S. Swails, Training Superintendent
*G. Van Middlesworth, Assistant Plant Superintendent, Operations
D. Wilson, Outage Manager
*K. Young, Assistant Plant Superintendent, Radiation Protection/Security

In addition, the inspector 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 July 2, 1990.

2. Followup (92701) (92702)

a. (Closed) Violation (331-88009-01a): Failure to Increase Operating Limit MCPR for Single Loop Operation. This violation was a result of the licensee failing to increase the operating limit MCPR, by adding 0.03 to the limiting MCPR, for single loop operation as required by Surveillance Test Procedure (STP) 46F002, "APRM/LPRM Operating Noise Data Collection and Thermal Limits Calculations for Single Loop Operation (SLO)," Revision 3, dated January 27, 1988.

In response to the cited violation, the licensee identified that the violation was a result of personnel error and that the additive value was erroneously omitted. Immediate corrective action consisted of reperforming the applicable steps of the STP by the reactor engineer, and a verbal briefing of the event by the Operations Supervisor to all shifts. This error resulted in a non-conservative error in MFLCPR of 0.013, with a calculated value of 0.740 verses the correct value of 0.753. Neither the technical specification (t.s.) MCPR safety limit nor MCPR Operating Limit was violated during the single loop operation evolution.

In addition, the licensee has modified STP-42F002 to reduce the possibility of miscalculation and required a supervisory level review of the procedure prior to it's completion. Special training concerning single loop operation was covered as part of Operator Requalification Training cycle 6 1988. This violation is closed.

b. (Closed) Violation (331-88009-01b): Standby Gas Treatment System (SBGTS) Handswitches Mispositioned. This violation was a result of control room back panel handswitches HS-5825A and HS-5825B to the SBGTS being identified in the closed position, contrary to Operating Instruction (OI) No. 170, "Standby Gas Treatment System," Revision 3, dated October 29, 1987.

Licensee investigation into the cause of the misposition identified that it was most likely an equipment tagout which indicated that the switches were erroneously left in the "closed" position after testing and inspection of SBGTS deluges. A review of valve electrical schematic identified that the handswitches control the position of the SBGTS intake valves only when the mode switch is in manual, thus automatic operation of the SBGTS was not effected.

The Operation Supervisor briefed all operating crews on the problem of mispositioned switches and the requirement for strict adherence with plant operating instructions. In addition, the STP-47B006, "Standby Gas Treatment System Bypass Cooling Test," was modified to include steps to ensure the handswitches are returned to the open position following the STP. A procedure review and subsequent modification to Administrative Control Procedure 1410.5, "Tagout Procedure," was completed to strengthen the procedure for restoration of equipment/systems. This violation is closed.

c. (Closed) Unresolved Item (331/89022-02(DRP)): Long Term Test Equipment Installation. This item was opened due to a licensee practice of installing test equipment for long periods without adequately evaluating its effect on safety equipment. After evaluating the inspector's concerns, the licensee determined that their procedures were not sufficient to ensure test equipment did not jeopardize the operation of safety equipment during long term installations. Nuclear Generation Division procedure 1410.6 was written to require that test equipment installed for over 24 hours or unattended for more than 1 hour will be considered as a Temporary Modification. As such, test equipment's effect on plant equipment will be evaluated through the licensee's Temporary Modification program, which has provisions for making 10 CFR 50.59 Safety Evaluation applicability determinations. The inspectors reviewed the procedure and determined it to be sufficient to control long term test equipment installation. The inspectors will review the implementation of this procedure in future inspections. This unresolved item is closed.

3. 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:

May 16, 1990 - Increase in Drywell leakage

May 17, 1990 - Control Rod Drive (CRD) Insert/Withdrawal lines found leaking

May 18, 1990 - National Pollutant Elimination Discharge System (NPEDS) Permit Violation (State of Iowa notification)

May 21, 1990 - Reactor Run Back due to under voltage on Instrument AC bus

May 22, 1990 - Shutdown Cooling Overpressurization

May 25, 1990 - APRM/Rod Block - flow bias setpoints found set nonconservatively

June 17, 1990 - "B" Circulating Water Pump trip

a. Drywell Leakage

On May 16, 1990, the licensee observed drywell unidentified leakage increase from a nominal value of 0.8 gpm to 1.1 gpm. Over the next few days, the unidentified leakage continued to increase up to 2.0 gpm. Drywell unidentified leakage finally stabilized at 2.3 gpm. Based on an initial evaluation, it appears that the leakage is attributable to the "A" inboard MSIV. The plant has been operating on three main steam lines (MSL) since April 22, 1990. While operating with one steam line isolated, the licensee has noted that the "A" outboard MSIV has experienced excessive stem packing leakage resulting in elevated heater bay temperatures. Elevated drywell temperatures have also been observed during the increase in sump leakages in the drywell. This has been more pronounced in the vicinity of the MSIVs. On May 28, 1990, unidentified drywell leakage was observed to have dropped from 2.3 gpm to 0.8 gpm for unknown reasons. The licensee has been unable to determine any known correlation between drywell leakage and plant activities ongoing at that time. The licensee is continuing to closely monitor drywell leakage.

b. <u>Control Rod Drive Insert/Withdrawal Line</u>

On May 17, 1990, the licensee identified two leaking Control Rod Drive (CRD) insert/withdrawal lines. These lines are located outside the drywell, within the air gap of the drywell shell and the reactor building concrete. CRD 30-07 withdrawal line was found with through wall pin hole leaks, and CRD 26-07 insert line was found with what appeared to be a circumferential crack approximately 200° with an accumulation of moisture or weeping water. The affected area is located in the heat affected zone of a seal weld between the insert/withdrawal lines and the drywell shell. The insert and withdrawal lines are composed of 304 stainless steel, schedule 160 pipe. The affected lines are located at drywell penetration X37C and X38C on the southwest bank of bundles that penetrate the drywell shell.

Initial corrective action has been to aggressively determine the extent or scope of the problem, fully insert CRD 30-07, and perform an engineering evaluation. Insertion of CRD 30-07 was taken as a conservative action by the licensee, separate from the engineering evaluation. The engineering evaluation, which was approved by the Operations Committee, was performed to provide a basis for continued operation. The evaluation identified postulated failures of these lines and the consequences of such failures. The failures have been previously evaluated in UFSAR Section 4.6.2.2. In addition, several detection methods have been employed to detect additional degradation or line failure. Further, the UFSAR states that the CRD insert and withdraw lines are not considered part of the reactor coolant pressure boundary (RCPB) and, therefore, the analysis provided in response to GDC-55, Reactor Coolant Pressure Boundary Penetrating Containment, is not applicable.

Initial swipe samples of the pipe have identified traces of chlorides on all bundles with traces of calcium present, which could indicate concrete as a source of the chlorides. However, the southwest quadrant is the only bundle that appears to have been affected. The licensee has initially planned to cut out CRD line 30-07 by obtaining a tree pam sample of the affected area, including the pipe and drywell shell. The removed weld from CRD 30-07 will be used to determine root cause failure. The information obtained will be used in evaluating the failure potential of the remaining CRD lines. The root cause failure analysis will be used to aid in formulating the extent of repair/replacement of the CRD lines. In addition to NDE and destructive examination being performed on CRD 30-07, the licensee is also performing visual and UT examinations on other CRD lines. The visual examination will consist of a boroscopic inspection of all welds that join the CRD lines to the drywell shell. The UT examination will only be performed on a sample of five lines with the scope of the inspection extended depending upon the results of the initial inspection.

While CRD 30-07 is being evaluated by the engineering consultant, the five additional lines in the affected area of the bundle (west side) will be cut to allow an ultrasonic examination (UT) to be performed. The UT probe will be inserted through the inside of the pipe to detect any defects. This is considered an open item (331/90009-02(DRS)) pending further evaluation into the failure mechanism and the repair of any affected lines by both the licensee and NRC. A reactor inspector from the Division of Reactor Safety will continue to follow the licensee's corrective actions.

c. Shutdown Cooling Piping, Overpressurization

On May 23, 1990, the licensee determined that a leak test, which was in progress on a portion of the shutdown cooling (SDC) piping, was responsible for pressurizing the line above its 150 psig rating. The leak test involved using a condensate service pump to pressurize the SDC piping in order to observe check valve leakage. An operating shift change occurred with the test still in progress. The oncoming shift was concerned that there was no means of pressure indication for the piping while it was being pressurized, and during the leak test, the shut down cooling header high pressure annunciator was rendered inoperable. After the operators had a pressure gauge installed in the piping which read 163 psig, they secured the condensate service lineup to the SDC piping and wrote a deviation report to document the overpressurization. Further review by the licensee determined that the design rating of the piping was 175 psig, and that the limiting component, a 150 pound flange, was actually rated to much higher pressure for the piping temperatures at the time of the event.

The inspector was concerned that the pressurization test was conducted under conditions which gave operators no indication of piping pressure, and which rendered a high pressure annunciator ineffective without a procedure or troubleshooting form to follow. Furthermore, the inspector expressed concern that an inadequate turnover of information about the test resulted in the operating shift being unaware of the actual and the acceptable pressure conditions in the SDC piping. This was complicated by the fact that since there was no test procedure or troubleshooting form, the shift operators did not have a point of contact to call about questions regarding the test.

The inspector reviewed the piping data and determined that although the piping was brought to a higher pressure than the engineer initially expected, and exceeded one flange rating, the piping was below it's design rating for the low temperature conditions involved.

After reviewing the licensee's procedure for conducting special tests (NGDP 107.0), the inspector determined that the test performed was not mandated to be performed under that procedure. However, the procedure was vague in it's description of what constitutes a special test.

The inspector interviewed an operator and the engineer involved in conducting the test. Communications of the details of the test appeared to be the major weakness. The engineer agreed that a troubleshooting form should have been used to give the operators more information about the test. This troubleshooting form could also have been the method to document how long the non-safety related condensate service water system should be aligned to the safety related SDC system to comply with OI-149 (RHR System Operating Instruction) caution statement which states that the time should be minimized. The fact that no pressure indication was available for the SDC piping during the test was a weakness. This was identified by one of the operators who properly took action to determine the pressure and secure the test. The licensee has issued a deviation report followup on this event. The inspectors will review corrective actions taken in response to the event after the licensee completes action on the deviation report.

d. APRM Flow Bias Setpoints

On May 25, 1990, the licensee determined that the flow biased scram and rod block setpoints were set non-conservatively high for all APRMs. The flow signal for the APRM flow bias calculation comes from reactor recirculation flow. Reactor recirculation loop flow is detected by transmitters sensing differential pressure (d/p) across a venturi downstream of each of the recirculation pumps. After the individual loop d/p signals are processed through a square root converter to produce a flow signal, they are sent to a summer whose output is total recirculation flow. The summer also converts the flow from gpm to a percent of rated flow signal which is used by the APRMs.

In February 1990 an operator in training noted a discrepancy between total recirculation flow in gpm and the percent of rated recirculation flow as read on the APRMs. In March the problem was brought to the system engineer for the neutron monitoring system. Rated recirculation loop flow, as stated in the UFSAR, is 28,800 gpm. Using this number as 100% loop flow, the total recirculation flow gpm reading at 83% reactor power was calculated to be about 83.5%. This differed from the 91.5% total recirculation flow reading at the APRMs. A review of the instrument data sheets showed that the recirculation flow summers used 26,550 gpm as the 100% recirculation loop flow value. This value represented 100% recirculation loop flow during initial plant startup. Over time, the ratio of jet pump flow per recirculation flow has decreased. Therefore, to get the same total core flow, recirculation flow has had to increase. The reason for this increase in recirculation flow to achieve equivalent total core flow is not yet clear. What is clear, is that as drive flow increased over time, the flow biased scram and rod block setpoints increased as well since the 100% value of 26,550 was never changed in the flow calculation sent to the APRMs. Therefore, the APRMs were receiving a recirculation flow signal greater than actual flow, and setting the scram and rod block setpoints accordingly.

The licensee wrote a deviation report to document the discrepancy, and raised the gain adjustment factor on the APRMs as a temporary solution to correct the setpoint error. The Engineering Department issued a Document Change Form (DCF) to revise the calibration procedure for the recirculation flow instrumentation. The revision set the appropriate current and voltage inputs to make a flow of 28,800 gpm read out as 100% recirculation flow at the APRMs. The APRMs were calibrated using this revision on June 26, 1990.

The inspector interviewed members of the licensee's engineering and technical support staff to determine why the initial recirculation flow settings were changed in the FSAR but not in plant procedures, and to determine the extent of engineering reviews of the procedure adequacy and results trending. The FSAR loop flow was changed from the original 27,100 gpm to 28,800 gpm in 1972, apparently to reflect the single loop flow. The procedure which calibrated the loop flow to the APRMs was written in 1974 to use 26,550 gpm as 100% flow. This was based on a GE review of startup testing data.

The inspector found that the surveillance results for STP-41A018 (APRM Flow Bias Instrument Functional Test) were not reviewed regularly by the engineering staff or trended. The inspector questioned several system engineers and found that if they do perform trending on their systems, it is just for a few selected points and not an overall review of the surveillance. The system engineers are not, in general, on the review chain for their system surveillances. Engineering department supervision indicated that system engineer duties such as trending that might have occurred previously had been deferred due to the extensive involvement of system engineers in maintenance planning efforts for the cycle 10/11 refueling outage. In addition, the system engineering staff has been reduced by approximately 50% in the last six months due to reorganization and personnel losses, without a similar reduction in workload. The system engineers have more systems in general to cover, and some systems remain without a system engineer. Licensee efforts are underway to replenish system engineer staffing somewhat. The inspectors are still concerned that with the increased maintenance planning workload and increased number of systems per engineer, the system engineer's ability to effectively monitor and trend system performance has been weakened.

The inspector also discovered that system engineers do not, in general, review the surveillance procedures on their systems for adequacy on a periodic basis. ANSI 18.7 of 1976, to which the licensee is committed through their Quality Assurance Manual, required a plant procedure review by knowledgeable individuals no less frequently than every two years. The inspector spoke with the supervisor of the surveillance and testing group to determine what review of procedures is performed. He indicated that plant procedure reviews are conducted based upon Nuclear Generation Division 1406.2 (Procedure/Instruction Preparation Review and Approval). This procedure calls for a biennial review of plant procedures. Like the ANSI requirement, the procedure allows a procedure revision to qualify for the biennial review. However, 1406.2 does not delineate the level of detail of review a procedure revision must undergo. Therefore, a procedure revision may take place with adequate review for the revision itself but not to meet the intent of the biennial review. Procedure 1406.2 also allows for a successful completion of the surveillance to satisfy the requirement for a procedure review. Thus a procedure could be missing key elements, but be performed satisfactorily as written and not be reviewed if its frequency is less than every two years. The inspector found several STPs in which the licensee relied on performance of the procedure as a biennial review. One has not been revised since October 1987, STP-41A018, but had been reviewed under the special STEEP program which has now ended. Another STP, BS-16 (ASME In-service Quarterly Cold Shutdown Instrument Calibration), has not been revised or reviewed since August 1987. This will be further reviewed as an unresolved item pending the licensee's and inspector's review of program adequacy (331/90009-01(DRP)).

No violations or deviations were identified in this area.

4. <u>Licensee Event Reports Followup (92700) (90712)</u>

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

a. <u>(Closed) Licensee Event Report (LER) 88013 (331/88013-LL)</u>: Inadequate Sealing of Level Switch Electrical Housing Combined with Cognitive Personnel Error Results in Core Spray (CS) and Emergency Diesel Generator (EDG) Actuations. This LER was the result of a spurious actuation of a yarway level switch combined with actuation of a second level switch as part of a surveillance procedure resulting in an inadvertent injection into the flooded-up refueling cavity by the "B" core spray system, and automatic startup of the two EDGs.

The root cause of the spurious switch initiation was improper sealing of the switch, which allowed moisture intrusion. The root cause of the inappropriate actuation of the second level switch was personnel error. Personnel error and a training deficiency also resulted in two additional auto-starts of the EDGs.

As part of the corrective action to prevent spurious action of the level switches, the licensee sealed the yarway level switches with silicon RTV to prevent moisture intrusion. During verification, the inspector identified that two level switches were not sealed with RTV per the maintenance action request (MAR) but instead sealed with grease. The licensee subsequently resealed these switches with silicon RTV. Corrective action to prevent recurrence included training for both operations and maintenance to emphasize the need to follow procedures as written, and to ensure that the control room is made cognizant of the completion of work on a component or any temporary halt in work. Also, as part of operator requalification training, operators were briefed on the lessons learned from the two additional EDG auto starts, including procedure modifications to identify logic constraints preventing immediate EDG shutdown after an auto start.

In addition to the above actions, the licensee has also taken action to isolate safety systems from initiation logic when such systems are not required to be operable. This action was taken to prevent unnecessary challenges to Safety Systems. Operating Instructions (OI) - 149, "Residual Heat Removal System" and OI-151, "Core Spray System," have been modified to include a means to disable portions of the LPCI, C.S. and EDG logic during periods when these systems are not required to be operable. This LER is closed.

b. (Closed) Licensee Event Report (LER) 89003 (331/89003-LL): Reactor Scram Due to Excessive Hydrogen Injection Into Feedwater System During Preparation for a Special Test. This LER documents a reactor scram during the preliminary steps of a hydrogen injection special test procedure. High steam line radiation caused by a larger than expected quantity of hydrogen being injected into the feed system was the cause of the scram.

The root cause of the event was the failure to verify proper construction of the test rig after it had been taken apart to repair hydrogen leaks. Oxygen and hydrogen flow orifices were swapped during reconstruction of the rig, resulting in an actual hydrogen injection rate approximately fourteen times the amount indicated on the flow indicator. Onsite follow-up of the reactor scram was performed by the resident inspectors and documented in inspection report 331/89003.

Long term corrective action was a revision of the Special Test Administrative Control Procedure that requires independent verification of proper assembly on performance of test rigs required for the performance of special tests. This LER is closed.

c. (Open) Licensee Event Report (LER) 89012 (331/89012-LL): Loss of Secondary Containment Due to Degraded Vent Shaft and Inadequate Test Methods. This LER documents the failure of the Reactor Building (RB) ventilation duct work inside the RB Exhaust Fan Room and the inability of the Secondary Containment operability test to detect a failure of this nature. While conducting an inspection of the RB Exhaust Fan Room a system engineer discovered a hole in the RB exhaust vent shaft approximately two feet from the ceiling of the room which could not be seen from outside the duct unless scaffolding was erected.

During a secondary containment isolation, the main plant exhaust fans in this room continued to exhaust air from areas outside of the secondary containment. This allowed the exhaust fan room to be at a negative pressure relative to the RB. The leak allowed the main plant exhaust fans to draw air from secondary containment.

Following the discovery, the secondary containment was declared inoperable. The duct work was repaired ensuring that it met seismic Class I criteria. After the repair, the secondary containment operability test was performed, without the main exhaust fans running, and failed. A number of small leaks in the secondary containment were found and repaired. The root cause of the failure of the RB exhaust vent shaft was determined to be due to not being installed in accordance with the original design specifications. The top section was designed to be a high velocity duct work; however, it was constructed as low velocity duct work. Repeated cycling caused deterioration of the duct work.

Long term corrective actions taken were:

- The licensee has revised the Secondary Containment operability test to preclude negative pressure regions adjacent to the Secondary Containment boundary during testing.

- Plant operating procedures were changed to require that the main plant exhaust fans are secured in the event that a Kaman Red Alarm is received in the Control Room. A 10 CFR 50.59 safety evaluation was performed to address the new fan line-up and the newly identified potential for SGTS bypass flow paths. No unreviewed safety question exists. The need for permanent plant modifications to the fan controls were reviewed; the licensee is determining the feasibility of reducing the RB bypass leakage to where the main exhaust fans may remain on with all RB exhaust being treated by the SGTS.

- Operability tests related to safety-related ventilation systems were reviewed for similar problems. No deficiencies were identified with the existing tests, based on the existing Technical Specifications.

Still open is the commitment to perform a review of all seismic Class I duct work against the original design documentation to ensure that the ventilation systems are installed as they were designed or by an acceptable alternate design.

Still open is the licensee commitment to perform Secondary Containment trending. Currently, there is no system engineer assigned the responsibility to perform the trending and no formal system for documentation and review of the data.

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 on the overall status of the plant and that they made frequent visits to the control room and regularly toured the plant. The inspector by observation and direct interview verified that the physical security plan was being implemented in accordance with the station security plan.

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.

The inspector observed plant housekeeping/cleanliness conditions and verified implementation of radiation protection controls. During the inspection, the inspector performed a control room walk down of the RCIC, HPCI, LPCI, and CS systems to verify operability by comparing system lineup with present valve lineup lists; observing equipment conditions that could degrade performance; and verified that instrumentation was properly valved, functioning and calibrated.

a. Fire Drill

The inspector observed the plant fire brigade's response to a fire drill involving a fuel oil fire simultaneous with a cooling tower fire. The brigade's response was timely and the members were all qualified despite the simultaneous drills. However, the inspector did note a problem with the coordination of the drill. The drill scenario included a simulated failed card reader at a vital area access. The brigade members used a key to open the door and did not card into the reader before entering the vital area. Since the security group was not forewarned of the details of the drill, they were not available to monitor access when the vital area door was left open. In addition, two members of the fire brigade were not on the access list for the vital area which they entered, although they were qualified to be put on the list. The licensee is taking corrective action to ensure that security procedures are not bypassed during drills. The inspectors will continue to monitor this area in future inspections.

b. Inoperable RHR Torus Suction Valve

On June 18, 1990, the licensee voluntarily entered a Limiting Condition for Operation (LCO) for the "A" train of Reactor Heat Removal System (RHR). The RHR system was removed from service to perform preventive maintenance and design modification activities. The main reason for performing these activities at this time was to reduce the scope of the outage by performing the maintenance and modification activities prior to the actual outage. Upon completion of maintenance and modification on valve MO-1989, RHR Torus Suction Valve, the licensee observed that the valve would not close during an operability test. The exact cause of the failure is unknown, but the valve was incapable of being closed either remotely or manually. The valve was verified to be in the open position by both local verification and control room position indication.

UFSAR Table 7.3-1 lists the lines that penetrate the primary containment and the types and locations of the isolation valves installed in each line. This Table describes MO-1989 as a Group B valve with no automatic isolation signal. Group B valves are on process lines that do not communicate directly with the reactor vessel, but penetrate the primary containment and communicate with the primary containment free space.

USFAR Section 3.1.2.5.7 discusses the DAEC conformance to GDC 56, Primary Containment Isolation. In this section, specific exception was taken to the GDC 56 requirements for effluent lines that originate from the suppression chamber (i.e., RHR, CS, HPCI, and RCIC suction lines). The FSAR states that due to the BWR suppression pool design, verbatim compliance with GDC 56 would require placement of an isolation valve underwater. For this reason, the RHR suction line contains two valves outside containment. These valves are also described as remote, manually operated valves that do not receive an automatic isolation signal because of their importance in combating an accident. Therefore, a specific exemption was taken to GDC-56.

The Duane Arnold Technical Specifications (T.S.) does not address this valve as a containment isolation valve. T.S. section 3.7.D, Primary Containment Power Operated Isolation Valves, only lists those containment isolation valves which receive automatic isolation signals. This class of valves do not have automatic closure initiation as other isolation valves because they are required to be open to support ECCS operations and therefore are exempt from automatic closure function.

The inspectors identified to the licensee that this valve performs a primary containment isolation function according to their FSAR, and it was not capable of performing that function with the valve open and incapable of being closed either remotely or manually. This valve is required to be capable of being closed remotely in the event of excess leakage from the ECCS system, to effect containment isolation.

As a result of the inability to comply with specific requirement of GDC 56, several conference calls were held between the licensee, Region III, and Nuclear Reactor Regulation (NRR) to discuss the licensee's course of action. The licensee subsequently performed an engineering evaluation, approved by the Operations Committee, providing their basis for continued operation. The licensee's safety evaluation concluded that continued operation with MO-1989 inoperable but in the open position until shutdown for cycle 10/11 refueling outage scheduled for June 28, 1990, was of minimal safety significance. The T.S. operability requirements for power operated containment isolation valves are not applicable to this valve. As this valve is assumed to be open in all the accident analysis and none of the modes of RHR are adversely affected; MO-1913 and MO-1921, RHR Torus Pump Suction Valves, provide acceptable redundant isolation capabilities in the unlikely event of an RHR pipe leak or rupture.

Further review of this issue is being taken by both NRR and Region III to determine whether this class of valves (remote manual isolation valves) should be included into T.S. to ensure appropriate action is taken consistent with their design basis. Further review is also required as to what action should be taken when an ECCS Torus Suction Valve (HPCI, RCIC, CS, and RHR) becomes inoperable to ensure continued reliability of containment integrity. As such, this is considered an open item (331/90009-03) pending further review by NRR and Region III.

No violations or deviations were identified in this area.

6. <u>Monthly Maintenance Observation (62703)</u>

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 is assigned to safety related equipment maintenance which may affect system performance.

The following maintenance activities were observed/reviewed:

- APRM Gain Adjustment
- HPCI Room Cooler Coil cleaning
- HCU 88-15 Cartridge Valve replacement
- ESW System Flow Orifices inspection/cleaning
- RHR/Core Spray Room Cooler Cooling Coil cleaning

- RHR Motor Operated Valve inspections

Following completion of maintenance on the APRMs, HPCI/RHR/CS room coolers, HCU and RHR valves, the inspector verified that these systems 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-41A006.2 - Discharge Volume High Water Level Instrument Functional Test/Calibration

STP-41A0016 - Average Power Range Monitor Weekly Trip Functional Test

STP-414B002-Q - General Service Water Effluent Line Monitor Functional Test and Calibration

STP-42A004Q - Main Steam Line High Flow Monthly Instrument Functional Test

No violations or deviations were identified in this area.

8. Temporary Instructions (TI)

(Closed) Temporary Instruction 2500/065 - TMI Action Plan Followup for items I.C.1.2.B, I.C.1.3.B, II.F.2.4, and II.K.3.57. Items I.C.1.2.B and I.C.1.3.B require revision and review of short term accident and transient procedures within the guidelines of NUREG-0737, "Clarification of TMI Action Plan Requirements," and Generic Letter 82-33, "Supplement 1 to NUREG-0737 - Requirements for Emergency Response Capability." Item II.K.3.57 requires that emergency procedures include verification of a source of cooling water prior to manual actuation of ADS in accordance with NUREG-0737. The licensee has made significant revisions to the Emergency Operating Procedures (EOPs), and has aligned their procedures to comply with the BWR Owners Group (BWROG) Emergency Procedure Guidelines (EPGs). NRC EOP inspection report 50-331/88200 evaluated the licensee's program for development and implementation of EOPs, as required by Generic Letter 82-33. This inspection, along with the EOP followup inspection documented in inspection report 50-331/90002, determined that the licensee's EOP implementation program was satisfactory and was in accordance with the NRC approved BWROG EPGs with a few minor exceptions. These exceptions are being corrected by the licensee and tracked on the open items list for Duane Arnold Energy Center. This closes items I.C.1.2.B, I.C.1.3.B, and II.K.3.57.

Item II.F.2.4 requires a review of reactor vessel water level instrumentation and replacement of inadequate instrumentation. Generic Letter 84-23 (Reactor Vessel Water Level Instrumentation in BWRs) addresses improvements to be considered to satisfy item II.F.2.4. A May 13, 1988, letter from the Office of Nuclear Reactor Regulation (NRR) to the licensee documented a review of the licensee's analysis of existing mechanical level indications and of proposed modifications to water level instrumentation to improve reliability. The proposed modification and the licensee's analysis of existing mechanical indicators were found to be acceptable based on the NRR safety evaluation. The modifications were installed in the 1988 refueling outage. The inspector reviewed the closeout documentation, prints, and physical layout of the instrumentation modifications to ensure they were installed in accordance with the commitment. This closes item II.F.2.4.

9. Management Meeting (30702)

On June 7, 1990, Commissioner James R. Curtiss of the Nuclear Regulatory Commission made an informational visit to Duane Arnold Energy Center (DAEC). The Commissioner was accompanied by K. A. Connaughton, Assistant to the Commissioner, and E. G. Greenman, Director, Division of Reactor Projects, Region III. The visit consisted of attending the morning maintenance meeting followed by a presentation by the utility covering such topics as plant history, current status, maintenance programs, improvement programs, and strengths and weaknesses. Following the presentation, a tour of the facility was made including the near-site plant simulator in the training center. At the conclusion of the tour, a brief exit meeting was held with the licensee.

10. Report Review (90713)

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

No violations or deviations were identified in this area.

11. 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 Paragraph 3d.

12. Open Items

Open items are matters which have been discussed with the licensee, which will be reviewed further by the inspector, and which involve some action on the part of the NRC or licensee or both. Open items disclosed during the inspection are discussed in Paragraphs 3b and 5b.

13. Exit Interview (30703)

The inspector met with licensee representatives (denoted in Paragraph 1) on July 2, 1990, and informally throughout the inspection period and summarized the scope and findings of the inspection activities. The inspector also discussed the likely information content of the inspection report with regard to documents or processes reviewed by the inspector. The licensee did not identify any such documents or processes as proprietary. The licensee acknowledged the findings of the inspection.