U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report No. 50-461/90016(DRP)

Docket No. 50-461 License No. NPF-62

Licensee: Illinois Power Company
500 South 27th Street
Decatur, IL 62525

Facility Name: Clinton Power Station

Inspection At: Clinton Site, Clinton, Illinois

Inspection Conducted: July 4 - August 21, 1990

Inspectors: P. G. Brochman
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Approved By: R. D. Lanksbury, Chief
Reactor Projects Section 3B

9/11/90
Date

Inspection Summary

Inspection from July 4 - August 21, 1990 (Report No. 50-461/90016(DRP))
Areas Inspected: Routine, unannounced safety inspection by the resident inspectors of licensee action on previous inspection findings; operational safety; event follow-up; radiological controls; maintenance/surveillance; emergency preparedness; engineering and technical support; and licensee event reports.
Results: Of the eight areas inspected, no violations or deviations were identified in four areas; two violations were identified in the following areas: (failure to properly store and control flammable material in safety-related areas - paragraph 3.a(4); and failure to install service water expansion joint tie rods resulted installed piping exceeding Code allowable stress values - paragraph 7.a). Additionally, two violations were identified in the following areas: (failure to perform a compensatory surveillance within the required time interval - paragraph 3.a(2); and installation on an unauthorized temporary modification - paragraph 7.c); however, in accordance with 10 CFR 2, Appendix C, Section V.G.1, a Notice of Violation was not issued. An unresolved item was identified which involved the failure to perform preventive maintenance on environmentally qualified flow transmitters.

Plant Operations

- Operator performance in responding to plant transients remained excellent. Operator response was timely and effective in stabilizing the unit and in preventing unnecessary reactor trips, especially with the containment isolation signal on August 16, 1990.

- Operator planning and prioritization of work declined as evidenced by one event where they allowed a one hour Technical Specification action statement to be missed (NCV 461/90016-01(DRP)).

- Numerous examples of poor control of flammable material were identified by the inspectors. Subsequent follow-up by licensee management identified more problems (NV4 461/90016-02(DRP)).

- A tagout of the Division I diesel generator did not specify the order of restoration of components; consequently, DC powered lube oil pumps started when DC control power was restored to the diesel, even though the pumps' suction and discharge valves were closed resulting in damage to the pumps.

Radiological Controls

- Two events occurred this report period where individuals did not follow radiological postings. In one case, licensee management deemed this action appropriate as the individual was responding to an emergency. In the other case, disciplinary action was taken.

Maintenance/Surveillance

- An automatic reactor trip occurred due to a miscalibrated volts/hertz relay on the main generator. Previous concerns had been identified on the calibration of nonsafety-related relays by licensee corporate personnel.

- Some instances of poor housekeeping, associated with ongoing maintenance activities, were noted by the inspectors. Corrective actions were initiated by management.

Emergency Preparedness

- The inspectors identified several concerns with the methods used to conduct an accountability drill and the results the licensee achieved (OPN 461/90016-03(DRP)).

Engineering and Technical Support

- Incorrect instructions during original construction resulted in shutdown service water piping being installed in a configuration where the piping exceeded the maximum allowable stress, as defined in the ASME Code. However, the actual yield strength of the installed material was less than the calculated stress (NV4 461/90012-01(DRP)).

- The inspector identified a less-than-adequate safety review in a temporary modification installed in response to a reactor trip. Two other events occurred in 1990 where inadequate reviews or obtaining required SRO approvals were not made (NCV 461/90016-04(DRP)).

- Problems with identification of Environmental Qualification (EQ) requirements were still occurring. One event involved a modification which installed two EQ transmitters; however, they were not identified as EQ. When they were finally identified as being EQ, the required annual preventative maintenance tasks were not written and performed within the allowed time period (UNR 461/90016-05(DRP)).

Safety Assessment/Quality Verification

- The quality of the licensee event reports (LER) issued this period remained good.

DETAILS

1. Persons Contacted

Illinois Power Company (IP)

#*J. Perry, Vice President
*J. Cook, Manager - Clinton Power Station
*R. Wyatt, Manager - Quality Assurance
*J. Miller, Manager - Nuclear Station Engineering
#*D. Gill, Manager - Projects and Assessment
#*F. Spangenberg, III, Manager - Licensing and Safety
*R. Morgenstern, Manager - Scheduling and Outage Management
*D. Gill, Manager - Nuclear Training
*J. Palchak, Manager - Nuclear Planning and Support
#*P. Yocum, Director - Plant Operations
*S. Rasor, Director - Plant Maintenance
#*D. Miller, Director - Plant Radiation Protection
#*R. Phares, Director - Licensing
*S. Hall, Director - Nuclear Program Assessment
#*K. Baker, Supervisor, I&E Interface

Soyland Power

*J. Greenwood, Manager - Power Supply

The inspector also contacted and interviewed other licensee and contractor personnel during the course of this inspection.

# Denotes those present during the management meeting on August 9, 1990.
* Denotes those present during the exit interview on August 21, 1990.

2. Action on Previous Inspection Findings (92702)

a. (Closed) Unresolved Item (461/89030-02(DRP)): Switchgear heat removal fans windmilling backwards at high speed. The inspectors had observed the safety-related switchgear heat removal fans, 1VX03CA/B/C to be windmilling backwards, at speeds up to 320 rpm during periods of standby operation when the normal VX fans were running. The inspectors had initially raised questions on the maximum current drawn by the motor when it would start in this condition. Subsequently, the inspectors raised questions on the rating of the coupling which connects the fan and motor. The inspector reviewed the vendor's calculations, which indicated that the maximum combined stress due to the bending stress and motor torque was 5239 psi, with an allowable stress of 6000 psi. The maximum torque transmitted by the motor was 440 ft-lbs, which was well within the 2300 ft-lb rating of the coupling. The calculations indicated that the locked rotor current duration would increase by 2 seconds, but that this was still less than the trip setting for the 90 amp breaker installed in the circuit. Based on this review, the inspectors believe that the fans would have performed their safety function, when they were discovered to be rotating backwards.

However, the vendor's calculations indicated that the heat generated in the motor was proportional to the increase in rotor slip and that a backwards speed of greater than 375 rpm could cause the slip to increase such that the limits of motor heat generation would be exceeded, and the motor damaged. Additionally, the vendor recommended a duty cycle of three starts a day, when the fans are rotating backwards. The licensee has committed to revise the operating procedures for the VX system to incorporate the vendor's recommendations. Based on this action, the inspectors have no further concerns; and this item is considered closed.

b. (Closed) Open Item (461/90011-03(DRP)): Analysis of possible water hammer in Division III of shutdown service water (SX) system. On May 24, 1990, an over pressure transient occurred on the Division III SX piping during a pump switching evolution. At the time of the event the licensee had performed walkdowns of the affected components to look for damage and performed a visual inspection of pressure boundaries before returning the system to service. The inspectors had requested to see the licensee's analysis of this pressure transient on installed instrumentation. The inspector reviewed correspondence from the Architect/Engineer (letter from R. K. Hindia to J. A. Miller, dated July 17, 1990) which stated that the maximum calculated pressure rise was to 245 psig; and that this was within the design pressure ratings of the instruments in Division III. Based on this information, the inspectors have no further concerns; and this matter is considered closed.

No violations or deviations were identified.

3. Plant Operations

The unit began the report period in coastdown to refueling outage RF-2 and operated at power levels up to 93% until 11:00 a.m. on July 9, 1990, when a reactor trip occurred due to a generator trip on volt/hertz (see paragraph 3.b(1)). The reactor was taken critical at 9:20 p.m. on July 10, and was synchronized to the grid at 7:12 a.m. on July 11. During power ascension, problems were encountered with the "B" reactor recirculation flow control valve and the unit was taken off-line at 3:01 a.m. on July 12 (see paragraph 3.a.(1)). The unit was taken critical at 2:52 p.m. on July 26, and was synchronized to the grid at 1:56 p.m. on July 27, 1990, and operated at power levels up to 93% for the rest of the report period.

a. Operational Safety (71707)

The inspectors observed control room operation, reviewed applicable logs and conducted discussions with control room operators during July and August 1990. During these discussions and observations, the inspectors ascertained that the operators were alert, cognizant of plant conditions, and attentive to changes in those conditions, and that they took prompt action when appropriate. The inspectors verified the operability of selected emergency systems, reviewed tagout records, and verified the proper return to service of affected components. Tours of the containment, auxiliary, fuel-handling, diesel and control, radwaste, and turbine buildings 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.

The inspectors verified by observation and direct interviews that the physical security plan is being implemented in accordance with the station security plan.

The inspectors observed plant housekeeping/cleanliness conditions and verified implementation of radiation protection controls. The inspectors also witnessed portions of the radioactive waste system controls associated with rad-waste shipments and processing.

The observed facility operations were verified to be in accordance with the requirements established under Technical Specifications, 10 CFR, and administrative procedures.

(1) <u>Problems with "B" Flow Control Valve Forces a Shutdown</u>

At 7:00 p.m. on July 11, 1990, with reactor power at 38%, operators were performing a power ascension and had shifted the "A" reactor recirculation (RR) pump to fast speed. Operators then attempted to close the "B" RR flow control valve (FCV) in preparation for shifting the "B" RR pump to fast speed. The hydraulic power unit (HPU) for the "B" FCV tripped several times and was reset each time. The FCV was eventually placed in the minimum position (0%) and the pump was shifted to fast speed. The valve position immediately jumped to 18% open. The reactor operator immediately tripped the hydraulic power unit and prepared to trip the reactor; however, no increase in recirculation flow rate nor reactor power was observed. Moreover, the pump flow and motor current remained constant. Additionally, loose parts monitoring alarms were received. The "B" RR pump was shutdown and the RR loop was isolated. Licensee management decided to shut down the unit and repair the FCV and to replace the seal cartridge on the "B" RR pump, which had been degrading over time. The unit was shutdown by 7:25 a.m. on July 12, 1990.

The licensee's investigation did not identify any obvious problems which would have caused the FCV to fail; however, several minor problems were found: some of the FCV hydraulic actuator and the FCV bonnet cover studs were loose, the actuator seals were leaking hydraulic fluid, and the LVT and LVDT (linear velocity and differential transformers) were out of calibration (the valve position had drifted to 48% open by the time the shutdown was completed, even though flow through the valve and the HPU were secured). The licensee replaced the actuator with a spare and also replaced the LVT and LVDT. The studs on the bonnet cover were retorqued and the studs on the "A" FCV were checked. The FCV was instrumented and tested and performed normally.

Additional work completed during the outage included: replacement of the "B" RR pump seal cartridge, resetting of the "B" RR loop discharge isolation valve's limit switches, installation of a temporary modification to monitor vibration on the "A" and "B" RR pumps, installation of a planned field alteration to source range channel "D", replacement of two "Rosemount" pressure transmitters in accordance with NRC Bulletin 90-01, and repair of various steam leaks. The outage was completed on July 27, 1990.

Performance during the outage was adequate. The licensee issued a list of lessons learned after the outage and identified areas for improvement.

(2) Compensatory Surveillance Not Performed Within Required Time Interval (LER 461/90014)

On July 12, 1990, the unit was in Hot Shutdown (operational condition 3) with reactor pressure at 390 psig and reactor temperature at 440 F. An orderly plant shutdown was in progress due to the event described in paragraph (1) above. At 9:25 a.m. a forced cooldown was initiated by dumping steam to the main condenser. At 10:50 a.m., control room operators tagged the Division III diesel generator (DG) out-of-service and declared it inoperable. The DG was taken out-of-service for planned maintenance.

Technical Specification 3.8.1.1.d required that with the Division III DG inoperable, when in operational condition 3, that the operability of the offsite AC sources be demonstrated within 1 hour by performing Surveillance 4.8.1.1.1.a. At 11:10 a.m., the reactor operator (RO) and control room supervisor (SRO) became occupied with controlling a reactor water level transient, in addition to the forced cooldown which was in progress.

Reactor water level was stabilized by 11:50 a.m. and at 12:00 p.m., the Shift Supervisor (SRO) noted the status of the Division III DG and inquired if the required surveillance had been completed. The control room supervisor responded that it had not been completed and directed that it be performed. The surveillance was satisfactorily completed at 12:15 p.m.

The cause of the event was personnel error by the licensed operators. They understood the requirement and tracking system for Technical Specification surveillances. However, they became preoccupied with controlling reactor water level and cooldown rate. The inspector agrees that the focus of the individuals was appropriate, but that they could have utilized other individuals to perform the surveillance. Additionally, the surveillance could have been performed on a more timely basis. The licensee counseled the individuals on the need to prioritize work and reviewed this event with all other operating crews.

The failure to perform Surveillance 4.8.1.1.1.a. within one hour of declaring the Division III DG inoperable is a violation of Technical Specification 3.8.1.1. Since this violation met the criteria of Section V.G.I. of the Enforcement Policy of 10 CFR 2, Appendix C, a Notice of Violation was not issued and this issue is considered closed (NCV 461/90016-01(DRP)).

(3) Reactor Feed Pump Seal Leakage

On July 28, 1990, the inspectors noticed a significant amount of water, later calculated to be approximately 10,000 gallons, in the condensate pump room. The licensee stated that there was a problem with the reactor feed pump seal water system during startup. The drains from this system would normally return to the main condenser. However, during startup, the feed pumps experienced excessive leakage due to the high discharge pressure from the condensate booster pumps and inadequately designed seals. The return line to the condenser from the seal drain tank could not handle this additional volume of water. The water then entered the turbine equipment drain system. The drain system was also not sized to handle this additional water. During some startups the water then backed up into the condensate pump room. The licensee stated that they were considering some modifications to the reactor feed pump seal system during the 1990 refueling outage. By the end of the inspection period the inspectors estimated that 110,000 - 140,000 gallons a day were leaking by the seals and all of it was being processed by rad-waste or returned to the main condenser.

(4) Control Of Combustible Materials

Technical Specification Section 6.8.1.g required that the Fire Protection Program be implemented by written procedures. Clinton Power Station procedure CPS No. 1893.01, paragraph 6.0, required that the storage of flammable liquids in safety related areas was prohibited. Paragraph 8.2.8.2 required that Class IB liquids be kept in approved/listed safety cans.

On July 12, 23, 24, and 27, 1990, the inspectors discovered a flammable liquid, acetone, in approved containers but unattended in four locations. They were; the 755' elevation in the fuel building, the 737' elevation in the drywell, the 707' elevation in the Auxiliary Building, and the 702' elevation in the Control Building. These are all safety-related structures. On July 12, 1990, the inspectors discovered acetone in an unapproved container in the fuel handling building.

The failure to control acetone was a violation of Technical Specification Section 6.8.1.g (461/90016-02a(DRP)). The failure to store acetone in an approved container was a violation of Technical Specification Section 6.8.1.g (461/90016-02b(DRP)).

(5) Division I Diesel Generator DC Powered Lube Oil Pumps Damaged

On May 3, 1990, while restoring the Division I diesel generator's lubricating oil pump, the operators failed to identify and open the isolation valves on the DC powered lubricating oil pumps. Consequently, when the DC control power was restored to the diesel, the pump began to run, with its suction isolated. The condition was discovered by the operator completing the clearing of the tagout. The control room was notified and the diesel generator was declared inoperable. Subsequent inspection of the pumps showed, that they had both been damaged when they were run without an oil supply. The licensee investigation determined the cause of this event was due to operator error. The tagout had been modified after its initial development to include the pumps' suction and discharge valves; however, no special instructions were added to open the valves before the DC control power breaker was closed. The licensee documented this event in Condition Report 1-90-05-012.

No deviations were identified, however two violations were identified, for one of the violations no Notice of Violation was issued.

b. Onsite Event Follow-up (93702)

The inspectors performed onsite follow-up activities for events which occurred during July and August 1990. This follow-up included reviews of operating logs, procedures, Condition Reports, Licensee Event Reports (where available), and interviews with licensee personnel. For each event, the inspector developed a chronology, reviewed the functioning of safety systems required by plant conditions, and reviewed licensee actions to verify consistency with procedures, license conditions, and the nature of the event. Additionally, the inspector verified that the licensee's investigation had identified the root causes of equipment malfunctions and/or personnel errors and that the licensee had taken appropriate corrective actions prior to restarting the unit. Details of the events and the licensee's corrective actions developed through inspector follow-up are provided in paragraphs (1) and (2) below:

(1) Generator Trip due to Improperly Set Volts/Hertz Relay results in Turbine Trip and Reactor Trip (LER 461/90013)

At 10:58 a.m. on July 9, 1990, with reactor power at 91%, an excessive volts/hertz annunciator was received. The operator began to reduce generator voltage, but 45 seconds later a generator trip occurred. The generator trip caused a turbine trip which initiated an automatic reactor trip. The main generator and transformers have a two stage volts/hertz relay to protect this equipment from an over-flux condition. Excessive magnetic flux can cause overheating and significant damage. The ratio of voltage to frequency is used to measure this parameter.

With the automatic (or AC) voltage regulator engaged, the volts/hertz relays have a setpoint of 110%, with a 45 second time delay (relay 59/81-1); and a 118% setpoint, with a 2 second time delay (relay 59/81-2). This equates to a relay setting of 121 volts and 129 volts, respectively. There was also an alarm for each of the setpoints.

Following the trip, all systems responded as designed and the unit was stabilized in mode 3. Reactor water level shrank past level 3, an expected transient, which caused a containment isolation on groups 2, 3, and 20. When the reactor operator was restoring reactor water level, the reactor was over fed which resulted in level rising to 71 inches on the upset scale. This caused a level 8 actuation and a feedwater pump trip.

Upon investigation, the licensee discovered that relays 59/81-1 and 59/81-2 were set incorrectly, at 115.3 V and 125.5 V. These relays had been calibrated on March 10, 1990, by maintenance work request MWR D09100. The MWR did not provide detailed job instructions nor reference the design specifications, but instead relied on past history and technician expertise. The NRC had previously commented on problems with calibration of protection relays in inspection report 461/90002(DRP). The licensee checked other relays that were calibrated at the same time, and did not identify any other problems. The licensee believed the most probable cause of this error was personnel error or a fluctuating voltage supply to the test instruments.

As corrective action, the licensee recalibrated and tested the relays. A temporary modification was made to deactivate the trip feature for the 110% relay, to see if setpoint drifting could be part of the problem. Also, this relay was typically taken out of service after a generator is synchronized at the licensee's other units (fossil). Detailed procedures for calibration of these relays are being written. New digital test equipment had been purchased for use in calibrating protective voltage relays. This should eliminate any fluctuating voltage problems affecting test instruments. Operating personnel were briefed on this event and the system design.

The inspector has reviewed the post trip review report to verify it addressed all required areas. The unit was returned to service at 7:12 a.m. on July 11, 1990. Inspector concerns regarding the safety evaluation for the temporary modification are discussed further in paragraph 7.b.

(2) Containment Isolation Signal During Maintenance (LER 461/90015)

At 10:54 a.m. on August 16, 1990, a partial actuation of Division II of Nuclear Steam Protection System (NSPS) occurred. Control and Instrument (C&I) technicians were removing a digital signal conditioning card (DSC) from its rack at the time of the event. The DSC serves as a buffer between the plant sensors and the NSPS logic system. The Division II systems and/or components that were affected, responded as follows; Shutdown Service Water Pump B started, Standby Gas Treatment System B started, Reactor Water Cleanup system isolated, upper Fuel Pool Cooling system isolated, Component Cooling Water system inside containment isolated, Containment Continuous Purge isolated, Fuel Building Ventilation isolated, Containment Fire Protection isolated, Fission Product Monitoring system isolated, H2O2 Analyzer isolated, Automatic Depressurization System air supply shifted to its backup bottles, Containment Cycled Condensate isolated, Containment Service Air isolated, Containment Makeup Condensate isolated, the Containment Equipment and Floor Drain Sumps isolated, and a half scram signal was received.

The Division II partial actuation was in only momentarily. The operators reset it immediately. The reactor recirculation pumps lost their cooling water; which, if not restored within one minute, required that the pumps be tripped and the reactor scrammed. The operators were within seconds of manually scramming the plant and tripping the RR pumps when component cooling was restored. The licensee reviewed the temperature records for the RR pumps and determined that the temperatures did not exceed the design limits during the transient. Additionally, an auxiliary operator was able to get to and start the standby drywell chiller, before a reactor scram on high drywell pressure occurred. When drywell cooling is lost, drywell pressure rises rapidly, due to the high temperatures The setpoint of 0.68 psig was typically reached within five minutes of losing drywell cooling and causes a reactor trip and full emergency core cooling system actuation.

This DSC was replaced earlier in the week using the same maintenance work request. The licensee determined that when the technicians had removed the card, they had shorted out some of the card's edge connectors, which caused the event. The inspectors will perform an additional review in a subsequent report, after the LER is issued.

No violations or deviations were identified.

c. Engineered Safety Features System Walkdown (71710)

The inspectors performed a walkdown of the High Pressure Core Spray (HPCS) and Standby Liquid Control (SLC) systems to verify their status. The inspectors verified that valves, circuit breakers, and switches were in their correct position; hangers and supports were made up properly; housekeeping and cleanliness levels were appropriate; valves were operable and did not have excessive packing leakage; combustible and flammable materials were controlled; components were labeled and lubricated; instruments were installed, functioning and calibration dates were current; locked valves were appropriately secured; and local and remote position indicators agreed.

There were no discrepancies noted during the walkdown. The inspectors noted that there were Maintenance Work Request tags on the SLC tank outlet valves which stated that their seats leaked by. The licensee was planning on working those valves during the upcoming refueling outage.

No violations or deviations were identified.

d. Preparations for Refueling (60705)

During review of a Technical Specification amendment, the inspectors identified a concern with controls over the containment suppression pool make-up dump valves. Technical Specification Bases 3/4.6.3 stated, in part, that "During refueling, neither automatic nor manual action can open the make-up dump valves." However, procedure CPS No. 3007.01C002, "Refuel System Checklist," lined up the dump valves in the standby mode. In the standby mode the dump valves would open automatically. The inspector requested the plant operations staff to evaluate this apparent inconsistency.

The plant operations staff indicated that the [illegible]ing procedure CPS No. 3007.01, "Preparations For and Recove[illegible]efueling Operations," contained instructions within th[illegible]e, to red tag the dump valves shut. The inspector reviewed [illegible]-203 which was used during the RF-1 refueling and it indic[illegible]t the dump valves, and their respective control switches and circuit breakers, had been red tagged in the correct position. Additionally, the operations staff submitted a request to revise checklist C002 to delete lining up the dump valves in the standby mode.

No violations or deviations were identified.

4. Radiological Controls (71707)

a. Entry Into a High Radiation Area Without Required Dosimetry

The inspectors reviewed a condition report (CR No. 1-90-07-053) which described an event wherein a radwaste operator entered a high radiation area without proper dosimetry. On July 23, 1990, maintenance personnel were disassembling valve 2WF211A under maintenance work request (MWR) C41455 to attempt to remove an obstruction in the line. When the valve bonnet was removed, water began to flow out of the valve, even though a tagout had been hung to isolate the valve for maintenance. The mechanic plugged the hole with his gloved hand and his assistant contacted the radwaste operations center (ROC) for assistance. A radwaste operator responded to the scene and entered the high radiation area to check that the tagout isolation valves were shut. The radwaste operator was wearing a TLD and low range pocket dosimeter, but not a high range pocket dosimeter and a ALNOR (self reading/alarming dosimeter), as was required for entry into this high radiation area.

The tagout was verified to be correct and the spilled water was cleaned up. The licensee initiated a dose assessment and determined that the individual did not receive a significant dose. Licensee management evaluated this event and determined that this entry was appropriate under these circumstances. The inspectors have reviewed this event and concur with this evaluation.

b. Individual Enters a Clean Area Without Performing the Required Whole Body Frisk

On July 11, 1990, a quality assurance auditor was performing a surveillance on a security door in the control building, 800' elevation entrance to the control room complex. The auditor observed an individual enter the control room complex without performing a whole body frisk. The control room complex was posted as a clean area and all personnel who entered it from the radiologically control area were required to first perform a whole body frisk, as required by procedure CPS No. 1024.40. The individual was confronted as he exited the clean area and processed through the personnel contamination monitor, which did not indicate any contamination. A contamination survey was performed of the clean area, with no contamination indicated. The individual notified his supervisor and continued with his fire watch tour, until a relief was obtained. The individual reported to the radiological protection office and was counselled on the importance of observing all monitoring requirements. Subsequently, the individuals dosimetry was pulled and a critique was held. As corrective actions the licensee discussed the need to heed radiological postings with plant staff and disciplinary action was taken against the individual.

No violations or deviations were identified.

5. Maintenance/Surveillance (61726 & 62703)

Station maintenance and surveillance activities of the safety-related systems and components listed below were observed or 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 affected components or systems were removed from and restored to service; approvals were obtained prior to initiating work or testing; quality control records were maintained; parts and materials used were properly certified; radiological and fire prevention controls were accomplished in accordance with approved procedures; maintenance and testing were accomplished by qualified personnel; test instrumentation was within its calibration interval; functional testing and/or calibrations were performed prior to returning components or systems to service; test results conformed with Technical Specifications and procedural requirements and were reviewed by personnel other than the individual directing the test; any deficiencies identified during the testing were properly documented, reviewed, and resolved by appropriate management personnel; work requests were reviewed to determine the status of outstanding jobs and to assure that priority was assigned to safety-related equipment maintenance which may affect system performance.

a. Reactor Water Cleanup System Modification Installation

On July 27, 1990, a Control and Instrumentation (C&I) crew was sent to replace the actuator on a Reactor Water Cleanup System (RWCU) valve. One of the crew noted, upon review of the work at the job site, that a potentially hazardous condition would exist if the job were performed as defined. The crew left the work area and reported to their supervisor, who halted the job.

The work had originally been scheduled for Saturday, July 28, but was moved up, due to concerns with reactor water conductivity. The job planner did not do a walkdown of the job site, because it was in a high radiation area. The replacement actuator had not arrived from the vendor when the planner was required to make up the work package, so he was unable to specify the specific work steps in the vendors manual necessary to install the actuator which had been received. The planner assumed that the actuator was to include the cylinder only and not the yoke which supports the cylinder and is attached to the valve body. This type of valve required that the packing gland, the pressure boundary between the fluid in the Reactor Water Cleanup System (which is at 1200 psig and 110 F), be disassembled. The C&I crew member noted the discrepancy between the planned job and the actual work that was required. If the C&I technicians had proceeded with the job the packing gland would have blown out probably resulting in injury to the C&I crew. The licensee estimated that the leakage rate could have been up to 100 gallons per minute, but the RWCU automatic isolation system would promptly isolate the system and reactor safety would not have been jeopardized.

The licensee held a critique and determined that personnel error was the cause in this event. The corrective actions taken were to require maintenance planners to specify work steps or sections of vendor manuals, when they are to be used, and to brief all maintenance personnel on this event.

b. Maintenance Work Area Cleanliness

The inspectors noted during a number of tours of the power block that the cleanliness of work areas was poor. There was trash, tools, and other equipment strewn about. The control of flammables, as referenced in paragraph 3.a(4) of this report, was also a problem. Additionally, material was often left at the job site for days and sometimes weeks after the work was completed. The problem seemed to be most acute in contractor work locations. The licensee was going to change their RP procedures to allow the removal of material from C-Zones after it had been properly bagged.

No violations or deviations were identified.

6. Emergency Preparedness (82301)

Evaluation of Accountability Exercise

The inspectors observed an announced accountability drill and evacuation of nonessential personnel from the protected area, on August 10, 1990. There were 418 personnel inside the protected area at the beginning of the drill and at the end of 30 minutes 144 persons were unaccounted for. After 48 minutes, 48 persons remained unaccounted for and the drill was terminated. These two numbers were skewed due to the method utilized to perform the drill.

Members of the emergency response organization (ERO), who are considered essential, and do not evacuate, did not report to their assigned locations, such as the Technical Support Center (TSC) or Operational Support Center (OSC) and perform a muster, but remained at their normal work areas. All nonessential persons were accounted for by having them evacuate from the protected area. The accounting of ERO personnel was simulated by the use of a muster list of those ERO persons who had been present in the protected area two days before the exercise. After a suitable delay to simulate the mustering process, the list was given to security for the accountability drill. The result of this process was that 47 people were indicated as being present in the protected area who were really not there. Additionally, to reduce the size of the list, a printout of the individuals present inside the protected area was not initiated until 19 minutes after the drill was begun, to allow those individuals who were inside the protected area and would evacuate, time to do so; thereby, reducing the initial number of individuals on the list which must be compared against those mustering in the emergency response facilities.

Consequently, the corrected results were that 97 individuals (23.2%) were unaccounted for after 30 minutes and 1 individual was unaccounted for after 48 minutes. Approximately 129 persons remained inside the protected area, with 289 people evacuating the protected area. Within 20 minutes 281 people had evacuated, and all non-essential persons had evacuated within 30 minutes.

The inspectors expressed several concerns to licensee management over the high number of unaccounted for individuals after 30 minutes. Less than 5 to 10 individuals missing was performance typically observed by the NRC during other emergency exercises; and while not a goal, it is a qualitative number to compare with the 97 individuals unaccounted for at Clinton Station. The second concern related to the fact that the ERO members did not report to their assigned locations and have a muster taken. The licensee's ability to rapidly count those individuals and transmit that information to security, for the comparison to be completed, was not demonstrated.

These concerns were compounded by the fact that the licensee had not conducted a full scale accountability drill for five years, but had limited the accountability to a preselected group of 50 persons during the annual emergency preparedness exercise. The inspectors noted that this practice had been accepted by the NRC.

Subsequent to the end of this report the inspectors were informed that the licensee intended to perform a full scale accountability drill during September 1990 in lieu of a 50 person limited demonstration as had previously been the practice. It was also noted that all individuals inside the protected area, except those engaged in critical in-process work would participate in the drill. Evaluation of this drill will be followed as an open item (461/90016-03(DRP)).

During discussions between licensee management and emergency preparedness personnel the inspector noted that the licensee had appeared to have established a nexus between accountability and evacuation. The licensee's method of performing an accountability utilized the evacuation of nonessential personnel. The inspectors noted that Regulatory Guide 1.101 contained guidance which indicated that protective measures for site and general emergencies should include evacuation of nonessential personnel.

However, the inspectors also noted that an accountability may be conducted at lower levels of emergency classification, if deemed appropriate by the station emergency director. Also, evacuees should not be evacuated into a greater danger. Consequently, the inspectors believe that it may be appropriate, in some circumstances, to conduct an accountability, but not an evacuation. Therefore, a licensee should have the capability to do so.

No violations or deviations were identified.

7. Engineering and Technical Support (92700 & 37700)

   a. Inoperable Expansion Joints on Service Water Piping to Diesel Generators (LER 461/90010)

   This event was originally reviewed in inspection report 461/90012(DRP) and identified as an apparent violation (461/90012-01(DRP)). An enforcement conference was held on June 5, 1990, to review the circumstances surrounding this event and two others. This conference is documented in inspection report 461/90014(DRS). After additional review of information provided by the licensee, the NRC has determined that this event does not warrant escalated enforcement; consequently, this event has been evaluated against the criteria specified in 10 CFR 2, Appendix C, Supplement I and the results are specified below.

   On May 2, 1990, with the unit at 100% power, maintenance personnel were cleaning essential service water (SX) system expansion joint 1SXQ4MA, when they observed water leaking from it. The licensee decided to replace the expansion joint and on May 4 the system engineer determined that the joint had expanded beyond its original design length and that its tie rods were missing. A walkdown of the diesel generator and SX expansion joints revealed that seven other SX joints did not have tie rods. This affected all the Division I and II diesel generators' SX piping. The tie rods were installed on the division III diesel generator SX piping. The tie rods restrained how far the expansion joint could expand axially. The expansion joint served as a vibration insulation device between the dies generator and the SX piping.

The licensee requested that the vendor evaluate the stresses on the expansion joint, using the as-found expansion. On May 8, the vendor determined that the expansion joints were acceptable in their expanded condition. The vendor recommended that tie rods be installed.

The licensee had their Architect/Engineer (A/E) evaluate the piping stresses for the expanded condition. The A/E determined that the original pipe stress analysis had assumed that the tie rods were installed to limit the axial expansion of the joint. At the same time, the licensee identified that two supports were damaged or not in proper alignment. Based on these affected supports and the length of time necessary to perform a new piping analysis, the licensee elected to declare the Division I and II DGs inoperable at 6:40 p.m. and commenced a shutdown at 10:10 p.m. The unit reached cold shutdown at 5:15 a.m. on May 10, 1990.

The licensee's investigation determined that the tie rods had been improperly removed during original construction due to misidentification of the tie rod lugs as lifting lugs. This condition had existed since the issuance of the operating license on September 29, 1986, until May 8, 1990. The construction documents had directed the removal of lifting lugs after the expansion joints were installed. The A/E performed a stress analysis of piping, pipe supports, expansion anchors, and auxiliary steel using a worst case, as-found, configuration.

This analysis indicated that calculated stresses were greater than the allowable design yield strength; however, a review of records (Certified Material Test Reports) indicated that the calculated stresses of the material were less than the actual yield strength of the installed material. The licensee's conclusions were that even during a safe shutdown earthquake the SX piping would not have failed or lost its pressure integrity.

The leaking expansion joint was examined and the leak was determined to have been caused by knifeline pitting due to galvanic corrosion between the stainless steel in the expansion joint and the carbon steel in the joint's end collar.

10 CFR 50, Appendix B, Criteria III, required that measures shall be established to assure that applicable design basis are correctly translated into specifications, drawings, procedures and instructions. The American Society of Mechanical Engineers, Boiler

and Pressure Vessel Code (Code), Section III - Division I, Subsection ND-3100 and ND-3649.1 (1974 edition) required that Code class 3 piping and expansion joints be designed to ensure that the design allowable stress values reflect the design pressure and mechanical loads and are within the limits specified in the Code. The SX piping and expansion joints were Code class 3. The failure to ensure that the procedures and instructions used to install the expansion joints resulted in a final equipment configuration which was consistent with design assumptions and within the design allowable stress values is a violation of 10 CFR 50, Appendix B, Criteria III (461/90012-01(DRP)). Based on the corrective actions taken, no response to this violation is required and this issue is considered closed.

No deviations were identified, however, one violation was identified.

b. Temporary Modifications

As part of the post trip review for the reactor trip (see paragraph 3.b.1), the inspectors examined the safety evaluation for Temporary Modification 90-029. The inspectors identified a concern with the safety evaluation. The description of the modification to relay 59/81-1 was accurate, in terms of which lead was to be lifted; however, the discussion on what this modification did and what was affected was inadequate. This modification disabled the 110% trip on the volts/hertz relay. Left intact was the alarm feature at the 110% trip, the alarm and trip feature at 118%, and the DC instantaneous trip. The safety evaluation was accurate but not informative.

Additionally, the inspector reviewed two condition reports which detailed problems with temporary modifications (CR Nos. 1-90-04-089 and 1-90-05-044). With regard to 04-089, this CR discussed an event on March 9, 1990, when the off-gas system was taken out-of-service (OOS). While it was OOS a temporary modification was installed by maintenance work request C55263. However, the required SRO approvals were not obtained before the off-gas system was returned to operation.

CR 05-044 discussed an event on May 9, 1990, when an unapproved temporary modification was found installed on damper OVC12YA. On March 27, 1990, a maintenance request was initiated to repair damper OVC12YA, when it was found closed and a large pool of oil was found on the floor under its hydramotor actuator. Temporary modification 90-15 was approved and installed to block open this damper. With the damper closed the temperatures in the control room complex became excessively low. On April 25, 1990, work on the hydramotor was begun and temporary modification 90-15 was removed. The work was not completed and the package was left open. Temporary modification 90-15 was not reinstalled. On May 9, 1990, the mechanics, upon recommencing work, discovered a pipe wrench and rope being used to hold the damper partially open.

This was an unapproved and inappropriate temporary modification. 10 CFR 50, Appendix B, Criterion V, required that matters affecting quality be accomplished in accordance with prescribed instructions. Clinton procedure CPS No. 1014.03, paragraph 8.2, required that the shift supervisor or assistant shift supervisor review the temporary modification, complete a safety evaluation, and approve its installation. The licensee's corrective actions included immediate removal of the unapproved temporary modification and an extensive investigation by Operations in an attempt to identify the origin of the modification (which was unsuccessful). The failure to approve the temporary modification installed on damper 0VC12YA was a violation of 10 CFR 50, Appendix B, Criterion V. Since this violation met the criteria of Section V.G.1. of the Enforcement Policy of 10 CFR 2, Appendix C, a Notice of Violation was not issued and this issue is considered closed (NCV 461/90016-04(DRP)).

No deviations were identified, however one violation was identified for which no Notice of Violation was issued.

c. Environmental Qualification

The inspectors reviewed a condition report issued by the licensee (CR No. 1-90-07-048) which documented the failure to perform a required preventative maintenance task on two flow transmitters, 1FISCC191A and 1FISCC191B. These instruments monitor component cooling water flow to the fuel pool cooling pumps and are required to be environmentally qualified. The contact resistance of the snap switches in the transmitter was required to be verified at 1 ohm or less, annually. Additionally, o-rings were required to be replaced annually. These transmitters were installed as part of a modification, which did not appear to receive adequate evaluation against environmental qualification requirements contained in 10 CFR 50.49 nor in scheduling the maintenance tasks once the requirement was identified. This issue will be followed as an unresolved item (461/90016-05(DRP)).

No violations or deviations were identified, however one unresolved item was identified

8. Safety Assessment/Quality Verification

Licensee Event Report (LER) Follow-up (90712 & 92700)

Through direct observation, discussions with licensee personnel, and review of records, the following LERs were reviewed to determine that the reportability requirements were fulfilled, immediate corrective action was accomplished, and corrective action to prevent recurrence had been accomplished in accordance with Technical Specifications. Based on these reviews, these LERs are considered closed.

LER No.	Title
461/90010-01	Tie Rods not Installed on SX Expansion Joint Causes Diesel Generators to be Outside Their Design Bases

461/90014 Compensatory Surveillance not Performed Within Required Time Interval

LER 461/90010 is discussed further in paragraph 7.a. LER 461/9014 is discussed further in paragraph 3.a(2).

No violation or deviations were identified.

9. Management Changes

During the report period Mr Dick Gill was named manager of training, in addition to his duties as manager of projects and assessment, following the death of the incumbent.

10. Items For Which A "Notice Of Violation" Will Not Be Issued

The NRC uses the Notice of Violation as a standard method for formalizing the existence of a violation of a legally binding requirement. However, because the NRC wants to encourage and support licensee initiative in the self-identification and correction of problems, the NRC will not generally issue a Notice of Violation for an issue that meets the tests of 10 CFR 2, Appendix C, Section V.G.1. These tests are: 1) the issue was identified by the licensee; 2) the issue would be categorized as Severity Level IV or V violation: 3) the issue was reported to the NRC, if required; 4) the issue will be corrected, including measures to prevent recurrence, within a reasonable time period; and 5) it was not a issue that could reasonably be expected to have been prevented by the licensee's corrective action for a previous violation. Issues involving the failure to meet regulatory requirements, identified during the inspection, for which a Notice of Violation will not be issued are discussed in paragraphs 3.a(2) and 7.b.

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 7.c.

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. An open item disclosed during the inspection is discussed in paragraph 6.

13. Meetings

a. Management Meetings (30702)

On August 9, 1990, Mr. A. B. Davis, Region III Administrator and members of his staff met in Glen Ellyn, Illinois with Mr. J. S. Perry and members of his staff denoted in paragraph 1 of this report. This meeting was held to discuss the recent performance of Clinton Power Station and to review licensee program initiatives and performance in the radiological controls area.

b. Exit Interview (30703)

The inspectors met with the licensee representatives denoted in paragraph 1 at the conclusion of the inspection on August 21, 1990. The inspectors summarized the purpose and scope of the inspection and the findings. The inspectors also discussed the likely informational content of the inspection report, with regard to documents or processes reviewed by the inspectors during the inspection. The licensee did not identify any such documents or processes as proprietary.