U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Report Nos. 50-373/89017(DRP); 50-374/89017(DRP)

Docket Nos. 50-373; 50-374 Licenses No. NPF-11; NPF-18

Licensee: Commonwealth Edison Company
Post Office Box 767
Chicago, IL 60690

Facility Name: LaSalle County Station, Units 1 and 2

Inspection At: LaSalle Site, Marseilles, IL

Inspection Conducted: June 10 through July 24, 1989

Inspectors: R. Lanksbury
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8/3/89
Date

Inspection Summary

Inspection on June 10 through July 24, 1989 (Reports No. 50-373/89017(DRP); 50-374/89017(DRP))

Areas Inspected: Routine, unannounced inspection conducted by resident and regional inspectors of operational safety; surveillance; maintenance; Licensee Event Reports; ESF system walkdowns; Quality Assurance Program Implementation; onsite followup of events at operating power reactors; onsite followup of written reports of nonroutine events at operating power reactors; radiation occurrence reports; ALARA; and licensee self assessment capability; and engineering evaluation of CILRT temperature sensor changes.

Results: Of the ten areas inspected, there was one violation identified. During this inspection period, there were nine Emergency Notification System (ENS) notifications, two of which were courtesy calls for potential Quality Assurance (QA) deficiencies with Main Steam Isolation Valve (MSIV) actuators identified by the licensee's QA organization. Two ENS calls pertained to problems with the Unit 2, Division III battery charger, one ENS call pertained to the second occurrence of the loss of the Unit 2 System Auxiliary Transformer (SAT) and the associated system isolations and Engineered Safety Feature (ESF) actuation, one ENS call pertained to a partial ESF of the Unit 1 reactor water cleanup system that resulted from the Unit 2 SAT event, one ENS call pertained to the High Pressure Core Spray (HPCS) system being inoperable because of its Emergency Diesel Generator (EDG) being inoperable, one ENS call

pertained to a dropped new fuel bundle, and one ENS call pertained to an inoperable Static-O-Ring (SOR) switch on the Reactor Core Isolation Cooling (RCIC) system. In addition, the licensee made two Technical Specification (TS) non 10 CFR 50.72, reports to the NRC of dead fish in the cooling lake. The one violation that was identified during this inspection period dealt with a shipment of byproduct material to a vendor not licensed to possess byproduct material. During this inspection period, the modifications to the spent fuel pool to incorporate the use of high density racks was essentially completed. The licensee also commenced receipt and storage of new fuel in preparation for the upcoming Unit 1 refueling/maintenance outage in September of 1989. During this inspection period, the licensee requested and was granted a Temporary Waiver of Compliance (TWC) for testing the Unit 2 Division I and II EDGs due to the Division III EDG being inoperable. Relief from these testing requirements had been available since 1984 (reference Generic Letter 84-15) but the licensee had failed to aggressively pursue this option.

DETAILS

1. Persons Contacted

+G. J. Diederich, Manager, LaSalle Station
*W. R. Huntington, Technical Superintendent
*J. C. Renwick, Production Superintendent
D. S. Berkman, Assistant Superintendent, Work Planning
J. V. Schmeltz, Assistant Superintendent, Operations
J. Walkington, Services Director
*T. A. Hammerich, Regulatory Assurance Supervisor
W. E. Sheldon, Assistant Superintendent, Maintenance
J. H. Atchley, Operating Engineer
W. Betourne, Quality Assurance Supervisor
M. G. Santic, Master Instrument Mechanic
W. J. Marcis, Site BWR Engineering Supervisor
*J. Spieler Quality Assurance
+W. Luett, Operational Lead for Health Physics
+M. Friedman, Health Physicist
+D. Hieggelke, Health Physics Services Supervisor
+F. Rescek, Corporate Radiation Protection Director
+G. Myrick, Corporate Radiation Protection Staff
J. Roman, Resident Engineer, Illinois Department of Nuclear Safety

+Denotes personnel attending the interim exit interview on July 5, 1989.

*Denotes personnel attending the exit interview on July 28, 1989.

Additional licensee technical and administrative personnel were contacted by the inspectors during the course of the inspection.

2. Operational Safety Verification (71707)

a. The inspectors observed control room operations, reviewed applicable logs, and conducted discussions with control room operators during the inspection period. The inspectors verified the operability of selected emergency systems, reviewed tagout records, and verified proper return to service of affected components. Tours of Unit 1 and 2 reactor, auxiliary, and turbine buildings were conducted to observe plant equipment conditions. These tours included checking for 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, by observation and direct interview, verified that the physical security plan was being implemented in accordance with the station security plan. This included verification that the appropriate number of security personnel were on site; access control barriers were operational; protected areas were well maintained; and vital area barriers were well maintained. The inspector verified the licensee's radiological protection program was implemented in accordance with the facility policies and programs and was in compliance with regulatory requirements.

b. The inspectors performed routine inspections of the control room during off-shift and weekend periods; these included inspections between the hours of 10:00 p.m. and 5:00 a.m.. The inspections were conducted to assess overall crew performance and, specifically, control room operator attentiveness during night shifts. The inspectors also reviewed the licensee's administrative controls regarding "Conduct of Operations" and interviewed the licensee's security personnel, shift supervisors and operators to determine if shift personnel were notified of the inspectors' arrivals onsite during off-shifts.

The inspectors determined that both licensed and non-licensed operators were attentive to their duties, and that the inspectors' arrivals on site appeared to have been unannounced. The licensee has implemented appropriate administrative controls related to the conduct of operations. These include procedures which specify fitness for duty and operator attentiveness.

c. On June 16, 1989, at approximately 5:28 p.m. (CDT), the licensee made a courtesy Emergency Notification System (ENS) phone call pertaining to the Unit 2 Main Steam Isolation Valve (MSIV) actuators on the 2A main steam line. This concern involved both the inboard and outboard MSIV actuators. During a product Quality Assurance (QA) audit of the Ralph A. Hiller Company of Pittsburgh, Pennsylvania, the supplier of four (4) recently purchased MSIV actuators, QA program deficiencies were identified such that the quality of the product was questionable. Two (2) of the four actuators were installed on the A steamline and the other two were being held as spare parts. At 5:30 p.m., the licensee started to decrease power in preparation for isolating the affected steamline. At 9:05 p.m. with Unit 2 at approximately 80% power, the operators closed the 2A outboard MSIV (2E21-F028A). This action was taken as a conservative administrative action pending further engineering evaluation.

On June 24, 1989, the licensee concluded the follow-up audit of the vendor and the analysis of the MSIV actuators that had been installed on the A inboard and outboard MSIV's. The licensee concluded that the vendor had some QA programmatic problems, but that the actuators were acceptable. On Sunday morning, June 25, 1989, at approximately 3:45 a.m., the licensee made a courtesy ENS phone call informing the duty officer of the outcome of their investigation and that they were preparing to reopen the A outboard MSIV. At 4:00 a.m. the licensee reopened the 2A outboard MSIV.

d. On June 26, 1989, the licensee noticed approximately 20 dead fish in the cooling lake. On June 27, 1989, further inspection revealed a count of approximately 196 dead fish. The area had experienced a very warm weekend and both Units 1 and 2 had been operating at or near full power for over 100 days. Per Appendix B of the Technical Specifications for Unusual or Important Environmental Events, the licensee notified the NRC within 24 hours. This notification will be followed up by a 30 day report.

On June 28, 1989, during a routine inspection of the shad nets, another 90 to 100 dead fish were found. Again, the NRC was notified and the Department of Conservation was also notified. Subsequently, the temperature in the area decreased significantly and so did the cooling lake temperature.

e. On July 15, 1989, at 9:19 p.m. (CDT), the licensee noted that the Unit 2 Division III (High Pressure Core Spray (HPCS)) battery chargers voltage and amperage were oscillating. The licensee declared the Unit 2 HPCS system inoperable. At 10:05 p.m. the licensee cross-tied the Unit 1 and 2 Division III batteries and buses in order to supply Unit 2 loads, turned the Unit 2 battery charger off, and declared the Unit 1 HPCS system inoperable. At 10:50 p.m. the licensee made the required ENS notification. The licensee investigated the cause of the fluctuations in voltage and amperage of the battery charger and determined that the cause was a bad phase A control board. The control board showed some signs of overheated components. On July 16, 1989, at 12:10 p.m. the cross-tie between the Unit 1 and 2 Division III batteries and buses was removed and at 1:30 p.m. the Unit 1 HPCS system was declared operable. At 5:35 p.m., after replacing the defective control board, the Unit 2 Division III battery charger and HPCS system were declared operable.

On July 17, 1989, at 5:45 p.m. (CDT), the licensee noted that the Unit 2 Division III HPCS battery chargers voltage and amperage were again oscillating. The licensee declared the Unit 2 HPCS system inoperable. At 6:30 p.m., the licensee cross-tied the Unit 1 and 2 Division III batteries and buses in order to supply Unit 2 loads, turned the Unit 2 battery charger off, and declared the Unit 1 HPCS system inoperable. At 7:35 p.m., the licensee made the required ENS notification. Subsequent to this event, the licensee replaced the B phase control board. After approximately 1/2 hour, the fluctuations returned. The licensee brought the vendor on site on the morning of July 18 to help with the investigation and repair. Over a period of several days, the licensee uncrosstied and recrosstied the Unit 1 and 2 Division III batteries and, in conjunction with the vendor, replaced various components and tried adjusting several settings for the battery charger. On July 23, 1989, at 9:15 a.m., the licensee declared the Unit 2 Division III battery charger and HPCS system operable.

f. On July 17, 1989, at 1:40 p.m. (CDT) while in the process of uncrating new fuel bundles for the upcoming Unit 1 refueling outage, one of the new fuel bundles fell out of its shipping container and landed on the refuel area floor. The licensee had just completed inspecting the shipping container and verifying that the fuel bundle restraint was secured and had just uprighted the container to a vertical position when the event occurred. Shortly after uprighting the container the fuel bundle restraint was seen to fall from the container followed by the fuel bundle. The bottom of the shipping container was approximately 4 to 5 inches off the floor when the bundle fell. The bundle was twisted

out of shape but did not appear to have ruptured. The licensee took swipe surveys in the area of the bundle and could not find any evidence of contamination that would have come from the fuel bundle. At 2:35 p.m. the licensee made an ENS notification in accordance with 10 CFR 20.403.(a).(4).. This action was taken by the licensee because they believed the value of the fuel bundle to be in excess of $200,000 (the criteria for a 1 hour report). The licensee's investigation of the root cause of the event revealed that the shipping container had a cracked weld on a wall stiffener. This allowed one side of the container to flex more than normal and would, when flexed, have allowed the fuel bundle restraint to come free. The licensee placed the damaged fuel bundle back in an undamaged shipping container and on July 24, 1989, shipped it and the damaged shipping container back to General Electric for inspection.

No violations or deviations were identified in this area.

3. Monthly Surveillance Observation (61726)

The inspectors observed Technical Specification required surveillance testing and verified for actual activities observed that testing was performed in accordance with adequate procedures. The inspectors also verified that test instrumentation was calibrated, that Limiting Conditions for Operation were met, that removal and restoration of the affected components were accomplished and that test results conformed with Technical Specification and procedure requirements. Additionally, the inspectors ensured that the test results 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 witnessed portions of the following test activities:

LOS-RH-Q1	Unit 1 RHR (LPCI) and RHR Service Water Pump Inservice Test for Operational Conditions 1, 2, 3, 4 and 5
LIS-PC-403	Unit 2 High Drywell Pressure LPCS Initiation, RHR (LPCI Mode) Initiation, ADS Permissive, and RCIC Isolation Functional Test
LIS-NB-102	Unit 1 Reactor Vessel Low Low Water Level (Level 2) Primary and Secondary Containment Isolation Calibration
LIS-NR-111	Unit 1 LPRM Flux Amplifier Gain Adjustment
LOS-MS-MI	Main Steam Isolation Valve-Leakage Control System Blower and Heater Operability Tests
LOS-FP-W2	Diesel Fire Pump Weekly Operational Check
LOS-DG-M3	1B(2B) Diesel Generator Operability Test

On June 19, 1989, at approximately 9:05 a.m. (CDT), the licensee was performing special test surveillance LST-89-068, Unit 2 Reactor Core Isolation Cooling (RCIC) High Steam Flow Isolation Calibration, when Static-O-Ring (SOR) differential pressure switch 2E31-N013AA failed. Switch 2E31-N013AA controls the outboard containment isolation valve for the RCIC system and also the isolation of the steam supply for the RCIC turbine. This placed the unit in an eight (8) hour LCO time clock for one (1) containment isolation valve inoperable. The licensee made the ENS phone call at 10:30 a.m. (the licensee is required to report all SOR switch failures due to previous problems and history of SOR switches at LaSalle).

At the time of this event, the Unit 2 High Pressure Core Spray (HPCS) system was out of service, on a fourteen (14) day time clock, for replacement of the Emergency Diesel Generator's (EDG) generator. The licensee anticipated potential problems with the testing of the RCIC SOR switches and because of HPCS being inoperable had replacements ready to be installed in the event a switch failed. The licensee replaced the failed SOR switch, calibrated it, and placed it back into service at 1:15 p.m. on June 19, 1989.

No violations or deviations were identified in this area.

4. Monthly Maintenance Observation (62703)

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

The following items were considered during this review: the Limiting Conditions for Operation were met while components or systems were removed from service; approvals were obtained prior to initiating the work; and activities were accomplished using approved procedures and were inspected as applicable. Other items considered also included verification that functional testing and/or calibrations were performed prior to returning components or systems to service; quality control records were maintained; and activities were accomplished by qualified personnel. Additionally, the inspectors verified that 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.

On June 20, 1989, at approximately 12:30 p.m., the Unit 2 A Turbine Driven Reactor Feedpump (TDRFP) was shut down and taken off line in order to lubricate the turbine to feedpump coupling and the control linkages. Due to the failure of the trip solenoid (SV-12) to trip the Unit 1's TDRFPs in early May 1989, the licensee elected to disassemble and inspect the SV-12 solenoid valve on the 2A TDRFP. This was successfully accomplished on June 21, 1989, with both the solenoid and valve being cleaned and functionally tested. The 2A TDRFP was then returned to service.

Early on June 23, 1989, the Unit 2 operators informed the technical staff that the 2A TDRFP emergency governor lock out normal light would not illuminate when the lock out switch was returned to the normal position. This indicated that the emergency governor and trip dump valve were still isolated and would not perform their intended functions. The instrument mechanics calibrated the pressure switches used to activate the indicating lights. Both switches were determined to be operable, but it appeared that one of the pressure switches was just short of tripping, thus preventing the normal light from illuminating. Pressure gauges were installed in place of the pressure switches and the lock out test performed again. The pressure gauges revealed that the oil pressure did not drop to its expected value when vented.

The inspector observed portions of the removal of the cylinder block which contained the lock out piston. Mechanical Maintenance noted that the lock out piston was bent and dirty. After cleaning and straightening the piston, the cylinder block was reassembled and tested. The normal light still would not illuminate. The cylinder block was again disassembled, this time the mechanics were extremely thorough in their cleaning of the cylinder block oil parts. A temporary supply of oil was then introduced to the cylinder block to visually verify that the oil could pass through the openings. The entire assembly was reassembled and retested. This time the normal light indication was received in the control room.

The lock out test was performed again and revealed that the trip dump valve would not trip. The mechanics installed a temporary line from the discharge side of the trip dump valve (SV-6) to the oil sump. When the solenoid was activated, no oil was discharged, indicating a problem with the solenoid. The SV-6 solenoid was removed and a manual gate valve was temporarily installed while the lock out test was performed again. The lock out test was performed successfully. A new SV-6 solenoid valve was installed and satisfactorily tested prior to returning the 2A TDRFP to service.

The inspector had observed several portions of this maintenance effort. Because of the problems the licensee has exhibited concerning the TDRFP trips, the resident inspectors will follow any upcoming TDRFP surveillances and/or problems pertaining to trip functions of the TDRFP.

No violations or deviations were identified in this area.

5. Licensee Event Reports Followup (90712, 92700)

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. The following reports of nonroutine events were reviewed by the inspectors. Based on this review it was determined that the events were of minor safety significance, did not represent program deficiencies, were properly reported, and were properly compensated for. These reports are closed:

374/89009-00 - Reactor core isolation cooling hi steam flow isolation switch failed diaphragm.

373/89015-00 - Missed fire protection valve position verifications due to procedural error.

373/89017-00 - Failure of 0 Diesel Generator cooling water pump breaker due to internal pitted contacts.

373/89018-00 - Reactor core isolation cooling isolation during warmup due to spurious high steam flow signal.

373/89020-00 - Failure of 250 VDC circuit breaker during ground isolation procedure rendering reactor core isolation cooling system inoperable.

373/89005-02 - Main steam high flow switch out-of-tolerance due to setpoint drift.

373/89009-01 - Reactor scram due to loss of main generator due to loss of Unit 2 system auxiliary transformer caused by inadvertent phase to ground fault during high wind conditions.

373/89019-00 - Charcoal laboratory sample results out of tolerance due to procedure deficiency.

373/89021-00 - Reactor core isolation cooling outboard isolation valve failure to open due to build-up of corrosion products on the stem nut.

b. The following report of nonroutine events involved violations of regulatory requirements. These reports are considered closed.

Event closure is being tracked by the associated violation. Appropriate cross references are provided.

373/89016-00 - Diesel Generator testing inadequacy and 2B Diesel Generator run solenoid failure (373/89010; 374/89010).

No violations or deviations were identified in this area.

6. <u>ESF System Walkdown (71707)</u>

The operability of selected engineered safety features was confirmed by the inspectors during walkdown of the accessible portions of the following systems. The following items were considered during the walkdowns: verification that procedures match the plant drawings, equipment conditions, housekeeping, instrumentation, valve and electrical breaker lineup status (per procedure checklist), and verification that items including

locks, tags, and jumpers were properly attached and identifiable. The following systems were walked down this inspection period:

Unit 2 High Pressure Core Spray
Unit 1 Standby Liquid Control

No violations or deviations were identified in this area.

7. Quality Assurance (QA) Program Implementation (35502)

The inspector performed an evaluation of the effectiveness of the licensee's implementation of its Quality Assurance (QA) Program. The overall effectiveness of the licensee's QA program implementation is directly related to the licensee's performance in specific functional disciplines, which is reflected in its operating history. Therefore, operating history is an indication of the effectiveness of the implementation of the QA program. The evaluation was conducted by review of the following:

a. NRC inspection reports for the past 12 months
b. SALP reports for the past 2 years (SALP 6 and SALP 7)
c. Outstanding regional Open Items List (OIL)
d. Licensee corrective actions for NRC inspection findings
e. Licensee event reports for the past 12 months

In addition to the above review, the facility's recent operating history and the collective knowledge of the resident and region based inspection staffs was also used in the evaluation process.

LaSalle's operating history has shown significant improvements in the number of ESF actuations and LERs attributable to personnel error:

ESF Actuations		Personnel Error LERS
1984	120	70
1985	72	46
1986	31	18
1987	28	12
1988	17	9
1989 (May)	8	3

The number of LERs has also shown a decline:

	LERs
1986	62
1987	61
1988	46
1989 (May)	26

No negative performance trends were noted and based upon the review the inspector has concluded that the QA program at LaSalle is effectively implemented.

No deviations or violations were identified in this area.

8. Onsite Followup Of Events At Operating Power Reactors (93702)

a. On May 1, 1989, a radioactive material shipment from Westinghouse Electric Company in Pennsylvania containing only an empty internally contaminated sea van arrived at the station. The sea van was on a flat bed trailer, designated as Radioactive Materials Empty Package UN 2908 and was labelled with Radioactive Label "EMPTY."

An arrival survey of the trailer and the sea van was performed and the results indicated no loose or fixed contamination on external surfaces. The sea van was then transferred to the Refuel Floor (843' RB). The bottom of the sea van was smeared and the results were less than 1K dpm/100 cm^2. The area of the trailer bed on which the sea van had resided was also surveyed and smearable contamination ranging up to 20,000 dpm/100 cm^2 was identified; an isotopic analysis indicated the primary isotope was cesium-137. The licensee attempted to decontaminate the tractor bed, but, due to the porous nature of the wood, the decon efforts were only minimally effective. As a result, the contaminated wood was removed from the trailer and disposed of as radioactive waste. The truck was then released.

The licensee discussed this matter with the inspector on May 2, 1989. The inspector reviewed the shipping papers and licensee survey and decontamination results, then forwarded this information, and his findings, to Region I on May 8, 1989.

b. On June 9, 1989, the licensee informed the NRC that, on the same day, a vendor located in California notified the licensee that two hydraulic actuators shipped to them by the licensee were contaminated. The vendor does not have a license to receive/possess radioactive material. The licensee dispatched two health physicists (HPs) to the vendor site on June 10, 1989, to perform surveys and provide radiological protection assistance. The HPs identified three spots of fixed contamination on the two actuators ranging from 1000 dpm to 7000 dpm, and several spots of removable contamination ranging from 1500 dpm/100 cm^2 to 2500 dpm/100 cm^2. Surveys were also performed of benches, equipment, floors, general office areas and personnel; no contamination was found. The HPs discussed with vendor personnel the survey results and radiological risks associated with the levels of contamination found. The components were returned to the licensee on June 12, 1989.

During this inspection the matter was reviewed by the inspector. The licensee issued an ROR and performed an investigation of the circumstances which allowed the contaminated components to be transferred to an unlicensed facility. The licensee found no radioactive material shipping papers accompanied these components nor were any unconditional release tags found with the packing material. Although the investigation revealed that the unconditional release tags were probably on the components before they

were shipped, the licensee could not be completely certain the surveys were performed because the survey results are recorded on the unconditional release tags and the tags are not saved. The transfer of radioactive material to persons unauthorized to possess such material is a violation (373/88017-01; 374/88017-01) of 10 CFR 30.41(a) requirements. This violation was the result of the licensee's failure to perform an adequate evaluation to determine that radioactive contamination was not present on the components.

On several occasions in 1988, the licensee identified numerous contaminated items outside the radiologically controlled area (RCA) but within their restricted area fence. This matter was discussed in Inspection Report Nos. 373/88024 and 374/88023-03, and an unresolved item was opened concerning the licensee's resolution to prevent recurrence of this problem. In that report the inspector indicated that attention should be given to ensuring that: a better survey program for releasing material into uncontrolled areas be developed; the routine uncontrolled area survey program be strengthened; and that a review be made to ensure that material leaving the RCA is surveyed.

In response to these concerns the licensee took several corrective actions, which are documented in Inspection Report Nos. 373/88028 and 374/88028, and the unresolved item was closed. However, as a result of the incident concerning failure to perform an adequate survey of material sent to an unlicensed facility, it appears the corrective actions taken to ensure quality surveys for materials being unconditionally released were not totally effective. These matters were discussed at the exit interview and will be reviewed at a future inspection.

c. On June 12, 1989, at 8:54 a.m., the Unit 2 System Auxiliary Transformer (SAT) Fire Protection System initiated, resulting in the deluge of the Unit 2 SAT. Approximately 76 seconds later a fault occurred at the phase A bushing on the primary side of the SAT. The fault was detected by Trip System I as Phase A Differential Current High, and by Trip System II as Phase A to Ground. Oil Circuit Breakers (OCB) 4-6 and 1-6 opened to isolate the SAT from the switchyard. The loss of power from the SAT resulted in the fast transfer of buses 252, 241Y, 242X, and 242Y, as designed, to the Unit Auxiliary Transformer (UAT). Bus 243 was deenergized upon the loss of the SAT due to the 2B Diesel Generator (High Pressure Core Spray (HPCS)) being out of service for maintenance. The 2B Diesel Generator is the alternate power source for bus 243. The Division III battery was immediately open circuited, to prevent the batteries from discharging. At 9:50 a.m., the licensee made the Emergency Notification System (ENS) notification on the loss of the Unit 2 SAT, the reactor building ventilation isolation, and the automatic starting of the control room ventilation emergency make-up train. The 2B Diesel Generator was returned to service at approximately 10:00 a.m. and power to bus 243 was restored. With the 2B DG supplying power to bus 243, it was necessary to

arc damage at the top and bottom of the bushing. The actuation of the deluge system has been attributed to a spurious electrical signal, possibly an electrical ground, which initiated the system. Maintenance personnel replaced the electrical parts, checked the system out and returned it to service. The licensee has reviewed the event and has not been able to determine a definite cause for the actuation. There have been no other occurrences of this kind at the site. The licensee does not plant on pursuing this event any further.

d. On June 14, 1989, at approximately 12:00 p.m., the Unit 2 System Auxiliary Transformer (SAT) had just been returned to service following the replacement of the primary A phase bushing. At this time the 2B Diesel Generator (DG) was supplying ESF bus 243, since its normal source of power (SAT) had been out-of-service. With the return of the SAT, preparations were underway to parallel the SAT (grid) to bus 243 and the 2B DG. The synchronoscope between the grid and bus 243 was enabled, and the Nuclear Station Operator (NSO) adjusted bus 243 voltage and frequency (via the 2B DG) until the grid and bus voltage were synchronized. The NSO then attempted to close the SAT feedbreaker (ACB 2432) to bus 243. The breaker failed to close. The NSO then placed the breaker control switch to the NORMAL-AFTER TRIP position and turned the synchronoscope off. This action would normally remove the breaker closure permissive. There are no automatic auto-close signals to this breaker.

At this point, Technical Staff assistance was requested. Breaker 2432 closing circuit voltages taken across the closing permissives (synchronoscope on, and 2432 handswitch in close) indicated no continuity between the handswitch contacts and the closing coil. Technical Staff and Operating personnel then proceeded to the 2432 breaker cubicle to investigate further. Physical inspection of the breaker revealed that it did not seem to be fully in the raised position. The breaker must be fully raised (racked in) in order for the breaker limit switches to operate properly. One of these breaker raised limit switches, operates in the closure permissive circuit. This limit switch prevents breaker closure attempts with the breaker not racked in (raised). It was determined by Technical Staff personnel that the breaker was not fully raised, hence the breaker raised limit switch was not physically closed preventing breaker closure. The closing and tripping fuses were removed, the breaker racked out (lowered), and racked back in, and the fuses re-installed. Closure circuit status was checked again, indicating the problem still existed. This breaker lower and raise procedure was repeated two additional times. On the third attempt, the breaker seemed to fully raise to the racked in position. When the closing fuses were replaced, the SAT feedbreaker to bus 243 unexpectedly closed.

ACB 2432 closure onto bus 243 immediately connected two separate sources of power (the grid and 2B DG) in an uncontrolled manner. Personnel in the control room did not observe any significant DG deviations from normal operation. The 2B DG did not trip, nor did its output breaker ACB 2433. The 2B DG continued to operate,

loaded to 2200KW, for approximately 2 hours following this event. The 2B DG was subsequently shutdown due to a fuel oil leak. It was then suggested by the off-site Operational Analysis Department (OAD) that an inspection of the 2B generator stator windings before returning the DG to service should be made. This inspection revealed that some stator windings had shifted position by approximately 1/4" to 3/8" (maximum). Resistance checks taken were satisfactory. At 6:15 a.m., on June 15, the HPCS EDG had not been returned to operable status so the licensee in accordance with the Technical Specifications declared the HPCS system inoperable and entered the Technical Specification action statement which requires that the HPCS system be returned to operable status within 14 days or commence shutdown of Unit 2. The licensee made the required ENS notification at 6:50 p.m. on June 15, 1989.

LaSalle Special Test LST-89-066, Unit 2 Division III SAT Feedbreaker ACB 2432 Troubleshooting, was performed to determine the cause of the breaker auto-closing. A bent stab was found during the performance of this test. The breaker with the bent stab was then removed from the SAT feed breaker cubicle. The breaker from the 2B DG output breaker ACB 2433 cubicle was then racked into the SAT feed breaker cubicle. Prior to raising the breaker, the secondary stabs were inspected for damage. Once the breaker was raised, continuity checks with the control circuit fuses removed were performed to verify that no short circuit paths to the closing coil existed. The SAT feed breaker was then closed to re-energize bus 243 with no abnormalities.

Although the damage to the generator appeared to be minor, the licensee decided to replace the generator. Because the generator replacement made the HPCS system inoperable, on June 16, 1989, the licensee requested a Temporary Waiver of Compliance from the LaSalle Unit 2 Technical Specification to test the remaining DGs every 8 hours if the Unit 2 B DG is inoperable. The NRC staff agreed to grant a Temporary Waiver of Compliance. This waiver was effective beginning June 16, 1989, and would remain effective until issuance of the Technical Specification amendment took place. The waiver was consistent with the NRC position contained in Generic Letter 84-15 which states that fast start testing of DGs should be reduced so that mechanical stress and wear in DG engines is minimized and reliability is not diminished. The licensee further agreed that they would submit a supplement to the existing Technical Specification amendment submittal dated March 16, 1989, in response to GL 84-15 by June 23, 1989, that would eliminate these unnecessary testing requirements and that would also address the testing requirements for all five diesel generators for both units. The NRC staff informed the licensee's management that its submittal in response to GL 84-15 for a Technical Specification change was deficient in that it failed to provide the changes that were required by this waiver. Had the appropriate changes been identified in their submittal, this waiver could have been avoided.

The replacement generator used was the old 2A DG generator that

had been rebuilt in 1984. Preventative maintenance under the supervision of the generator vendor (Ideal Electric) was performed on the rebuilt generator prior to installing it on the 2B DG. All of the work and testing performed on the 2B DG was documented in LST-89-074, 2B DG Return to Service Following Generator Replacement. The post replacement testing lasted approximately 56 hours. LST-89-074 also documented all of the Technical Specification surveillance requirements that were performed and which surveillances and/or special tests covered them.

General Electric (G.E.), the breaker vendor, was contacted by the licensee on the subject of the bent secondary stab. G.E. stated that these stabs should be inspected prior to raising the breaker, and that a protective cover should be placed on the stabs when the breaker is lowered and removed from the cubicle for extended periods of time, or when maintenance is being performed on these breakers. G.E. performed a site inspection of the SAT feed breaker and concurred that the cause of the auto-closure was the bent stab. The licensee's procedures for the feed breaker currently do not have steps to inspect for bent stabs or for installing a protective cover. Action Item Records (AIRs) have been written to revise and track the revisions to the licensee's procedures to include the steps necessary to perform the stab inspection and to install the protective cover.

The consequences of the event were minimal with respect to plant safety. This event, however, damaged a major piece of plant equipment. The HPCS system was declared inoperable as a result of this event. This placed Unit 2 in a 14 day timeclock, which would have expired on June 28, 1989. The licensee changed the status of the HPCS system from inoperable to degraded on June 27, 1989, at 5:30 a.m. and subsequently declared it fully operable. The Reactor Core Isolation Cooling System (RCIC) was fully operable as an alternate high pressure injection system. Division I and II Emergency Core Cooling Systems (ECCS) were also fully operable.

One violation was identified and no deviations were identified in this area.

9. Onsite Followup Of Written Reports Of Nonroutine Events At Power Reactor Facilities (92700)

Pursuant to a memorandum from the Region III Director, Division of Reactor Projects, dated May 1, 1989, and titled, Recent Operational Events, the resident inspectors have, during their routine walkthroughs of the facility, been observant to the licensee's administrative and physical controls of explosive materials. These materials include items such as pressurized hydrogen and oxygen cylinders. The inspections not only included storage and handling, but also were reviewed to ensure that these external hazards would not affect safety related components, equipment or facilities.

Since the issuance of the memorandum only two occurrences have been noted at the site. The first one was an oxygen bottle being temporarily stored in a "Nitrogen Only" storage area in the reactor building. The second occurrence was considered to be more serious, a hydrogen bottle was temporarily stored with two oxygen bottles. These gas bottles had been brought into the Unit 2 reactor building and were to be used as replacements in the post LOCA (loss of coolant accident) Containment Monitoring System. One item of concern was that these bottles had been temporarily stored in the rack for a longer duration than expected. A second concern was that hydrogen was stored with oxygen. The resident inspectors brought these observations to the attention of the site fire marshall and to plant management. The storage problem was immediately addressed and corrected. The licensee also investigated this concern and re-emphasized the sites' procedures and policies, pertaining to pressurized gas bottles to the licensee's staff.

The residents, during their inspections, will continue to monitor the licensee's use, handling, and storage of compressed gases and explosive materials on site.

No deviations or violations were identified in this area.

10. Radiation Occurrence Reports (RORs) (83750)

The licensee trends and categorizes RORs by work group and type of occurrence under the major classifications of external dose control, internal dose and surface contamination, administrative controls, and others. RORs are generally written for violations of station radiation control standards and procedures and any significant action or situation inconsistent with the ALARA philosophy. The inspector reviewed RORs generated pursuant to station procedure LRP-1150-1 for 1988 through the first quarter 1989.

During this period the licensee identified about ten incidents involving liquid spills which caused floor and area contamination. Several of the spills caused significant contamination control problems inside and outside the radwaste building. Most of the spills occurred in the radwaste building; four were caused by tank overflow. The inspector informed the licensee that this number of contaminated spills resulting in contamination control problems and causing unnecessary personal exposure appeared excessive. As a result, the licensee performed a review of the problem and found that most of the spills occurred during outages when water is transferred to support outage activity and that the major causes were poor planning, poor communication, personnel error (lack of training), mechanical failures, and system design problems. This matter was discussed at the exit meeting and will be further reviewed at a future inspection (Open Item 373/89017-02; 374/89017-02).

During this period the licensee also identified several incidents concerning improper High Radiation Area (HRA) controls. The events involved HRAs found unsecured/unattended, lost HRA keys, and ladders/scaffolding used in areas which could allow easy access to a HRA. None of the events involved HRAs in excess of 1000 mrem/hour. Although

corrective actions were taken for each individual event, the licensee determined that an underlying cause for most of the events was poor worker understanding of HRA controls. As a result, increased training on HRA controls will be included in Nuclear General Employee Training (NGET) and yearly retraining. The inspector informed the licensee that continuation of HRA control problems is unacceptable and that stronger actions by the licensee may be required. This matter was discussed at the exit interview and will be further reviewed during a future inspection (Open Item 373/89017-03; 374/89017-03).

The inspector also reviewed other RORs (thought to be significant) concerning failure to follow radiation protection procedures and good health physics practices. On each occurrence it appeared the licensee took adequate corrective actions and strong disciplinary measures.

No violations or deviations were identified in this area, however, two open items were identified.

11. ALARA (83728)

During a meeting between the licensee and NRC Region III personnel to discuss ALARA activities, the licensee stated that the 1989 projected person-rem goal was about 1000 person-rem. This goal was documented in Inspection Report Nos. 373/88028 and 374/88028 along with the results of the meeting. In a letter from the Nuclear Licensing Administrator to Region III, dated May 23, 1989, the licensee indicated that the projected dose for 1989 would be approximately 1650 person-rem based on historical data for planned work, and the established goal was about 1400 person-rem. During this inspection it was noted that to date, the station dose is running slightly below the projected dose and that significant licensee attention/effort has been given to exposure control for routine and future outage activities. This matter will be reviewed further during future inspections (Open Item 373/89017-04;374/89017-04).

No violations or deviations were identified in this area, however, one open item was identified.

12. Licensee Self Assessment Capability (40500)

During the SALP 8 period (March 16, 1988 - June 30, 1989), the inspectors attended several of the various meetings that the licensee holds as part of their self assessment function. These included the Event Frequency Reduction meetings, Error Free meetings, and Onsite Review meetings. As part of the review of this area, the inspectors, on a sample basis, verified that the applicable requirements of the Technical Specifications were met with respect to the composition, duties, and meeting frequency of the committee. Plant management involvement was evident during those meetings and in some instances the meetings included attendance by senior corporate management. The inspectors also noted that during the SALP 8 period that the offsite and onsite nuclear safety organization met with licensee management every quarter and reviewed the effectiveness of corrective actions associated with nonroutine events. The inspectors noted that identified issues were tracked and assigned to responsible

individuals for action and that dates for corrective action response were assigned. However, it was also noted that individual accountability for meeting assigned completion dates was lacking and that extensions appeared to be routinely granted.

No violations or deviations were identified in this area.

13. Engineering Evaluation of CILRT Temperature Sensor Changes (70307)

Commonwealth Edison Company plans to replace the RTD senors used to measure containment temperature during containment integrated leak rate tests (CILRT) with ceramic thermistors. Because of the few disadvantages that thermistors have when compared to platinum RTDs, such as nonlinearity, CECo purchased a limited number of the new detectors for trail tests which were conducted at the LaSalle Station.

On July 13, 1989, the inspector reviewed the test instrumentation setup, instrument calibrations, and some of the data obtained. Based on observations and discussions with the licensee the inspector has no concerns regarding the licensee's plans to replace the RTDs with thermistors for future CILRTs. The licensee plans to document the results of their study justifying the change from RTDs to thermistors. The inspector will review the documentation as part of the CILRT review for Quad Cities or LaSalle whichever takes place first.

No violations or deviations were identified in this area.

14. 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. Three open items disclosed during the inspection are discussed in Paragraphs 10 and 11.

15. Exit Interview (30703)

On July 5, 1989, an interim exit interview was held to cover the scope and findings of the inspection of radiological controls and events. The inspectors also met with licensee representatives (denoted in Paragraph 1) throughout the month and at the conclusion of the inspection period and summarized the scope and findings of the inspection activities. The licensee acknowledged these findings. The inspectors also discussed the likely informational contents of the inspection report with regard to documents or processes reviewed by the inspector during the inspection. The licensee did not identify any such documents or processes as proprietary.