U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Augmented Inspection Team

Report Nos. 50-373/89007(DRP): 50-374/89007(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: March 3 through 4, 1989

Team Members: S. Du Pont, Team Leader, DRP, RIII
R. Kopriva, Resident Inspector, LaSalle
D. Butler, Engineering Branch, DRS, Region III
R. Mendez, Engineering Branch, DRS, Region III
P. Shemanski, Licensing Project Manger, NRR

JJHarrison

Approved By: J. J. Harrison, Chief
Reactor Projects Section 1B

3/20/89
Date

Table of Contents

Attachments

A. Sequence of Events
B. Confirmatory Action Letter (CAL-RIII-89-007)
C. AIT Charter
D. NRC Letter, dated 3/8/89, Closing CAL Items 1-5 and authorizing Unit 1 restart
E. LaSalle Electrical Distribution Diagram

*J. C. Renwick, Production Superintendent
D. S. Berkman, Assistant Superintendent, Work Planning
J. V. Schmeltz, Assistant Superintendent, Operations
*P. F. Manning, Assistant Superintendent, Technical Services
*T. A. Hammerich, Regulatory Assurance Supervisor
*W. Morgan, Licensing Administrator
*J. Gieseker, Supervisor, Technical Services

*Denotes personnel attending the exit interview on March 4, 1989.

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

4. Description of the Event

On March 2, 1989, at 11:00 p.m. (CST), both Units 1 and 2 were operating at steady state power. Unit 1 was at 86% reactor power and had been operating continuously for 216 days. There was no major equipment out of service. Unit 2 was at 88% reactor power and had been on line for 20 days after just completing a 15 week refueling/maintenance outage. Unit 2 had no major equipment out of service.

At about 11:02 p.m. on March 2, 1989, both Unit 1 and Unit 2 experienced a common disturbance. Trouble ground alarms were recorded by the unit oscillographs indicating excessive loop currents through the two main transformer grounds. These trouble grounds alarmed in the control room. Approximately 17 seconds later the Unit 2 SAT C phase lightning arrester shorted through to ground causing a catastrophic failure of the lightning arrester. The failure of the lightning arrester caused the SAT differential relays to pick up which in turn caused Oil Circuit Breakers (OCBs) 4-6 and 1-6 on the Unit 2 345KV (Red) ring bus to trip (see Attachment E). These relays isolated the Unit 2 SAT. Additionally, a pole disagreement signal on OCB 4-6 was received indicating that the A, B or C phases on the OCB did not close simultaneously. The loads supplied by the Unit 2 SAT were transferred to the Unit 2 Unit Auxiliary Transformer (UAT). At approximately the same time, the Unit 1 phase A generator differential relay picked up which caused the generator field excitation breakers to open. This resulted in a main turbine trip, a trip of OCBs 9-10 and 10-11 isolating the generator from the Unit 1 345KV (Blue) ring bus and a reactor scram on Unit 1. The Unit 1 SAT was not affected and loads continued to be supplied by the SAT. All equipment appeared to function normally and the fault was cleared. At approximately 1:05 p.m., both the Unit 1 (Blue) ring bus and the Unit 2 (Red) ring bus were restored. However, annunciaters in the control room indicated OCB 4-6 (Unit 2) had not closed. Since both ring buses had been restored, the indicating light appeared erroneous. The following morning at 9:05 a.m., several electrical operators were sent to investigate why OCB 4-6 was indicating erroneously. The licensee personnel discovered that one of the two phase B OCB bushings was cracked and oil was leaking from the bushing. The electrical operators also discovered that in the OCB control panel a fuse link had become disconnected and an indicating switch had broken off its bracket. The licensee manually tripped OCB 4-6 and put the OCB out of service to perform maintenance.

1. General Description

On March 2, 1989, LaSalle Unit 2 experienced a fault on the Unit 2 station auxiliary transformer (SAT) and subsequent loss of the SAT. This event was rapidly followed by a second event on Unit 1 involving a turbine trip and subsequent reactor scram. During these events, all of the units' busses automatically rapid transferred from the affected bus supply to the unaffected bus supply. During these bus transfers, several system components appeared to not respond as expected. On March 3, 1989, the Augmented Inspection Team (AIT) was dispatched to the site by Region III.

2. Summary

The safety significance of the events were determined to be low and within the analysis associated with the loss of the system auxiliary transformer, loss of all grid connections and within the design basis accidents. Licensee management demonstrated conscientious involvement and provided sound evaluations of the event from a safety standpoint. The root cause of the loss of the Unit 2 System Auxiliary Transformer (SAT) was due to an internal failure of the "C" phase lightning arrester. A lightning to ground strike or other adverse weather conditions were not the cause of the event. The root cause of the Unit 1 reactor scram was due to an electrical system transient being sensed by the "A" phase differential relay. The relay setting was sufficiently low, but within calibration tolerences, so as to allow the short-lived transient in the 345KV switch yard to result in a turbine trip. The unit operators and staff responded to the events in a controlled manner.

The NRC issued Confirmatory Action Letter (CAL-RIII-89-007) to confirm the licensee's corrective actions associated with the Unit 1 scram and the Unit 2 loss of the SAT prior to restart of Unit 1. On March 8, 1989, items 1 through 5 of CAL were closed. Item 6 of the CAL remains open.

The AIT found two practices that did not appear to reflect good operating practices. The first practice pertained to operating both units' process computers and Hathaways (annunciator computer) on unregulated alternate power. This did not cause or contribute to the events, but did contribute to the difficulty of understanding and evaluating them. The second practice pertained to the documentation of test results associated with large electrical equipment. Some large electrical equipment is tested offsite by the CECo Operational Analysis Department (OAD) in Maywood, Il. OAD does not apparently record test data or maintain records of test data. These practices were identified as unresolved items in the details of the report.

No items of violation or deviations were identified.

3. Persons Contacted

*N. Kalivianakis, General Manager, BWR
*G. J. Diederich, Manager, LaSalle Station
*W. R. Huntington, Services Superintendent

A. Unit 2 Loss of the System Auxiliary Transformer (SAT)

The loss of the Unit 2 SAT was primarily due to the failure of the phase C lightning arrester. A review of the weather conditions on March 2, 1989, identified no rain, snow or thunder at 11:00 p.m. however humidity may have contributed to the lightning arrester's failure. Approximately 17 seconds before the failure of the lightning arrester, the Unit 1 and Unit 2 main transformers were experiencing greater than normal circulating currents through ground. Several annunciators indicating main transformer grounds alarmed in the control room. A review of the plant oscillographs indicated that there was no system or plant disturbance at this time. The higher than normal circulating ground current was probably due to the Unit 2 SAT arrester which had started to conduct current to ground. The main transformer ground detectors only indicated the presence of a ground but did not indicate where the faulty component or equipment was located. The conduction of current to ground in the lightning arrester was an indication the arrester was starting to fail. The failure of the lightning arrester caused a phase to ground fault which caused the SAT phase differential relays to isolate the SAT.

The 4KV non-segregated bus connection to the SAT may have also contributed to the loss of the transformer. After the SAT was out of service, the licensee attempted to take megger readings of the 4KV non-segregated bus. The megger results failed to meet the acceptance criteria of 3.4 M-ohms. At the time of the non-segregated bus connection megger check, humidity may have affected the megger results. The licensee subsequently found water on the bus, and moisture and dirt on one of the support bushings to the bus. The licensee dried the bus and cleaned the bushing. Subseouent megger readings were acceptable.

Following the isolation of the SAT from the 345 KV switch yard, several operator actions and system equipment responses occurred. Immediately after the loss of the SAT numerous alarms were received by both Unit 1 and Unit 2. On Unit 2 the operators immediately noticed that the reactor scram lights and reactor Control Rod Drive (CRD) Hydraulic Control Unit (HCU) accumulator lights were lit indicating a reactor scram. The Nuclear Station Operator (NSO) was about to place the reactor mode switch in shutdown, per procedure, when the NSO recognized that the reactor had not scrammed or received a scram signal. The operator realized that the unit had apparently lost the Reactor Manual Control System (RMCS). This was the result of undervoltage conditions existing on the RMCS associated with the automatic rapid bus transfer. The operator then reviewed the control panels and recognized that reactor vessel level was decreasing. Reactor feedwater was being supplied to the reactor via the 2A and 2B Turbine Driven Reactor Feed Pumps (TDRFPs). The 2A TDRFP was in 3-element automatic control and the 2B TDRFP was in manual control. Following the Unit 2 loss of SAT transient, the 2A TDRFP control signal decreased rapidly resulting in a lockup condition. The Unit 2 TDRFPs use

Lovejoy controllers for speed control of the feedwater turbines. A TDRFP lockup will occur if the Lovejoy electronics senses any rapid control signal change (increasing or decreasing). A rapid control signal change is interpreted by the logic system as a control signal malfunction. The Lovejoy system will attempt to mitigate the consequences of such a malfunction by locking up the TDRFP at the speed/flow at which the failure was sensed. In this case, the lockup occurred due to a rapidly decreasing control signal. The 2A TDRFP initially attempted to follow the decreasing control signal (i.e. began decreasing speed/flow) and locked up at a lower flow rate. Since the 2B TDRFP flow had not changed (2B TDRFP in manual), a feed flow/steam flow mismatch occurred and reactor vessel level began to decrease. The NSO immediately responded to the decreasing level by manually increasing flow on the 2B TDRFP. The NSO stopped the level decrease at 24.8 inches Reactor Water Level (RWL) (from the narrow range recorder) and level began increasing. The NSO, concentrating on level indication, did not realize that feedwater flow increased to a point where the feed flow was much greater than steam flow. By the time the NSO adjusted feedwater flow, the reactor level reached a maximum of 53.5 inches RWL (from the narrow range recorder). The reactor water level was then stabilized at approximately 36.0 inches. Reactor water level 8 (55.5 inches) was not achieved at any time during the transient. After the reactor water level was stabilized, the 2A TDRFP lockup was reset. The reason for the 2A TDRFP control signal failure was apparently due to a voltage drop on the controller power supply (bus 235X-3). The 2B TDRFP was unaffected. At the same time as the level transient, a second NSO on Unit 2 was instructed to decrease the reactor recirculation flow which would decrease the reactor power, thus helping to reduce the transient in progress. The NSO reduced power to approximately 66%.

Subsequent to the SAT trip, the Unit 2 Reactor Recirculation (RR) pump Flow Control Valve (FCV) Hydraulic Power Units (HPU) for both the Unit 2 RR pumps tripped causing the RR FCVs to lockup. The SAT normally provides power to the RR FCV HPUs. The loss of the SAT only removed power to the HPU pump and not the electronic control of the HPU. There apparently was sufficient residual pressure remaining on both units to perform the valve position change to reduce the reactor recirculation flow during the event.

Upon the loss of the Unit 2 SAT, prior to the transfer to the Unit Auxiliary Transformer (UAT), the Unit 2 leak detection system logic power failure alarm was received. This caused the Reactor Water Cleanup (RWCU) system, sensing a leak due to a momentary loss of control power to the leakage detection system, to isolate and close the 2G33-F001 (inboard) and 2G33-F004 (outboard) RWCU isolation valves. In addition, the RWCU pumps tripped. Additional equipment also tripped during the automatic rapid bus transfer from the Unit 2 SAT to the UAT. These included the station air compressor, four reactor building ventilation dampers, various area radiation monitors (resulting in the control room ventilation system shifting to emergency makeup), and the process computer. All of these components, with the exception of the process computer, were reset or restarted within five minutes of the undervoltage conditions associated with the rapid bus transfer.

At 1102:59 the transfer of power to the UAT was complete, the reactor power and water level stabilized, and the spurious alarms ceased.

B. Unit 1 Reactor Scram

Unit 1 experienced a reactor scram shortly after the loss of Unit 2 SAT. On March 2, 1989, the licensee was operating in a normal lineup with both the Unit 2 (Red) and Unit 1 (Blue) ring buses physically and electrically connected when the lightning arrester failed. The Unit 1 phase A generator differential relay sensed a fault in the switchyard and picked up to protect the Unit 1 generator. On March 3, 1989, the licensee removed and calibrated the Unit 1 phase A, B and C generator differential relays. The as-found calibration results indicated that phase A had the fastest pick time (3.7 cycles) and picked up at the lowest current (0.178 amps). Nominal calibration values are 0.200 amps (0.180 to 0.220) with a pick up time of 5 cycles (77 to 93 mseconds). The as-found values for the B and C phases were 0.203 amps with a pick up time of 5.1 cycles and 0.209 amps with a pick up time of 5.5 cycles, respectively. The previous calibration, performed on June 24, 1988, indicated that the A phase relay was within the nominal values. The AIT also reviewed the calibration records for the Unit 2 generator differential relays, last calibrated on November 2, 1988, and found that the minimum pick up values and times were comparable to those of the Unit 1 B and C phases. The AIT concluded that the lower than nominal values of the Unit 1 A phase relay was due to drift. Additionally, the AIT reviewed the oscillographs of the switchyard line currents and voltages at the moment the fault occurred. The review indicated that the 345KV system at LaSalle sustained the fault for five cycles following the initiating event. Since the fault was not cleared until five cycles after the lightning arrester failure, it is likely that the pick up of Unit 1 phase A differential relay was due to its fast pick up time and low current setting.

5. Review of Equipment Response During the Events

The AIT reviewed the various equipment responses that occurred during both events. The AIT found that the majority of the Unit 2 components that had tripped did so because of undervoltage conditions existing on various busses during the transfers from the SAT to the UAT. The SAT to UAT automatic transfer (approximately 0.13 seconds) functioned as designed. However, the severity of the undervoltage transient caused other Unit 2 components to trip. These components tripped to their fail-safe positions/conditions. The Unit 1 equipment response was similar but was due to low voltage conditions on various busses during the transfer from the UAT to SAT. During the transfer, bus voltage dropped because of the increased loads on the SAT. During the event, all of the ECCS and ESF functions were unaffected and were available to mitigate plant upset conditions. The AIT also reviewed the following specific equipment to determine the cause of failures, isolations or any unusual operations:

A. Unit 2 OCB 4-6 Failure

The AIT reviewed the problems experienced by the Unit 2 OCB 4-6. The licensee is continuing to evaluate the OCB problems with the pole disagreement or problems with the cracked bushing on the OCB for any possible relationship to the Unit 1 generator trip. However, the licensee stated that pole disagreement signals were fairly common when the high voltage independent pole OCBs are open or closed. Additionally, the licensee believes the cracked bushing on OCB 4-6 may have been caused by loose mounting bolts. A field engineer discovered loose mounting bolts on phase B OCB 4-6 when the OCB was taken out of service on March 4, 1989. The loose bolts may have caused excessive movement of the OCB during closing and tripping of the breaker. The movement of the OCB may have eventually caused the bushing to crack. The licensee has committed to tighten all loose mounting bolts in the LaSalle 345KV switch yard. The licensee is investigating whether the failure mechanism was electrical or mechanical. The licensee stated that the cracked bushing will be sent to the Technical Center in Maywood, IL. for analysis.

The AIT requested records relating to the testing of the OCB and the SAT. The licensee stated that the power factor test (doble test) and the travel test (timing) of the phase B 4-6 OCB had been performed but the results were not documented. The inspector was informed that oil samples from the 4-6 OCB and the Unit 2 SAT were acceptable, although no records were available for review at the site. Additionally, the licensee has not located the power factor testing records for the Unit 2 SAT. The lack of documented test result data associated with large electrical equipment is considered to be an unresolved item (373/89007-01 and 374/89007-01).

B. Units 1 and 2 Reactor Building Ventilation and Unit 2 RWCU System

During the events, several Primary Containment Isolation System (PCIS) components isolated without an apparent PCIS signal. These included the Unit 2 reactor water cleanup system inboard (2G33-F001) and outboard (2G33-F004) isolation valves, and two Unit 1 and four Unit 2 reactor building ventilation dampers. The AIT confirmed that a PCIS demand did not exist because of the events and as such, these components responded individually. In all cases, these components responded because of momentary undervoltage or low voltage conditions existing on their respective control power supply busses during the automatic rapid bus transfers. The conditions existed long enough for their respective trip relays to drop out.

In all cases, these components were reset shortly after the bus transfers.

C. Units 1 and 2 Station Air Compressors

During the events, both units experienced the loss of Service Air (SA) compressors. The Unit 2 SA compressor tripped during the automatic rapid transfer of busses from the SAT to UAT. The Unit 2 SA compressor is powered from bus 241X (UAT) and the compressor control power is supplied from 232A-1 (SAT). The transfer was slow enough that one of the compressor trip relays dropped out on undervoltage and caused the compressor to trip.

The Unit 1 SA compressor also tripped during the event on low voltage to the compressor trip relays. This occurred during the UAT to SAT transfer and the momentary reduction in voltage while the SAT was accepting all bus loads.

The SA compressors for both units were reset and restarted within five minutes of tripping. Because of the rapid restart of the compressors, instrument and service air pressure did not approach low pressure conditions.

The AIT also reviewed the operating procedures, LOA-IA-01, Loss of Instrument Air and LOA-SA-01, Loss of Service Air, and concluded that they were adequate to mitigate the loss of SA compressors during the events.

D. Process Computers and Hathaway Sequence of Event Recorders (SER)

During the event, the process computers and Hathaway SERs for both units were on their alternate power supplies. The process computers' Uninterruptible Power Systems (UPS) were out of service (in bypass) for maintenance. The failure of the Unit 2 System Auxiliary Transformer (SAT) lightning arrester caused an undervoltage condition on the affected supply busses.

The undervoltage was lower than what is normally expected during automatic bus transfers. The process computers were lost during the bus transfers and the licensee had difficulty evaluating the event and reinitiating the computers. The computers were restarted and restored to their normal power supplies by March 4, 1989.

The Hathaways' normal power source is the safety-related Direct Current (DC) system. The Hathaways are not safety-related. Field inputs are supplied from the annunciator system. The Unit 2 Hathaway was placed on alternate power (unregulated) as a result of a DC ground in one of the annunciator circuits prior to the events. The power source switch was performed to isolate the non safety-related system from the safety-related DC system. The licensee was unable to determine the reason for the Unit 1 Hathaway being supplied by its alternate power supply at the same time the Unit 2 Hathaway was also on alternate power. The Unit 2 annunciator ground was repaired and both Hathaways were restored to their normal power supplies by March 4, 1989.

The licensee indicated they had some difficulty in analyzing the event because of the loss of the process computers and inconsistent data from the Hathaways. Some data was obtainable from various chart recorders for both units and information documented in various logs. The automatic bus transfers caused the Hathaways to print multiple alarm entries. There was also considerable relay chattering which contributed to the inconsistent data. The licensee was able to sort out this data and provide the AIT with a complete sequence of events (Attachment A).

The AIT discussed with the licensee the availability of reliable sequence of event information. The licensee had no formal policy to ensure that when one unit's process computer was on alternate power for UPS maintenance that the other unit computer was not out of service for maintenance or on its alternate power supply. This would also apply to the Hathaways. The licensee has initiated an action item to review the AIT's concern. Review of the licensee's actions is considered an unresolved item (373/89007-02 and 374/89007-02).

E. Unit 2 RPS Alternate Power Supply Breaker Trip

During the event, the Unit 2 RPS was aligned to its normal power supplies. The alternate power supply was operable and in standby.

The alternate power supply Electrical Protection Assembly breakers (EPA) and the CB1 feed breaker were closed prior to the event. The EPA breakers, alternate power supply, opened during the SAT lightning arrester failure event. The alternate power supply source is turbine building 480V MCC 232B-1. The AIT reviewed the associated schematic diagrams and traced the alternate power supply source to the Unit 2 SAT. The AIT also reviewed the EPA trip logic and verified that the EPA breakers would trip on an undervoltage condition. During the automatic bus transfer from the SAT to the UAT, the duration of the undervoltage condition resulted in the EPA logic detecting undervoltage and tripping the EPA breakers.

F. Unit 1 "A" Reactor Recirculation Flow Control Valve (FCV)

During the event, the 1A reactor recirculation FCV servocontroller locked up due to actuation of the abnormal signal level trip. The FCV lockup appears to be a result of a power spike which affected the Flow controller's power bus, 131A-2.

The investigation indicates that a flow controller signal spike occurred approximately at the same time as the Unit 1 scram. At approximately 23 seconds into the scram, a FCV runback occurred after the 1B FW pump tripped. The 1B reactor recirculation FCV initiated a runback, the 1A FCV did not, indicating the controller had locked up. The controller signal spike also corresponded to the lockup alarm that appears on the Hathaway printout. The power source for bus 131A-2 is 6.9 KV bus 151. Bus 151 is fed from the Unit 1 UAT. The 1A FCV controller lockup occurred due to the momentary loss of voltage during the UAT transfer to the SAT.

Recorder traces were obtained to investigate the FCV response. These show that a controller spike occurs at about the same time as the Unit 1 scram. The trace indicates that the actual controller output did not exceed the setpoint for the abnormal signal level trip. The peak of the controller output was only about 85% demand. However, the controller signal spike confirms the existence of an electrical supply spike in the logic. This was sufficient to actuate the abnormal signal relay, which tripped the logic just as if the relay had been actuated by the signal monitor comparator. Occurring within 40 milliseconds of the abnormal alarm was a condition 1 alarm that would normally be associated with low or hot HPU oil, excessive filter dP or high servo error. This condition apparently did not exist since the HPU tripping did not occur from a persisting condition.

G. Unit 1 Static-O-Ring (SOR) Switches

During the event, the NSO observed that annunciator window E105, Reactor Vessel Low Water Level 3 Confirmed, and window B509, Channel A2/B2 Reactor Vessel Level 3 Low, reset at a higher reactor water level than was indicated. In the initial notification to the NRC, the licensee indicated that steam flashing may have occurred in an instrument line condensate pot.

The Unit 1 scram was a result of a main generator lockout. This initiated a turbine control valve fast closure and resulted in a full reactor scram. This type of event causes the reactor vessel pressure to increase. The SOR switches are connected with their high pressure port to the upper reactor level tap (reference leg). Flashing of a reference leg would appear as a higher reactor water level than was expected. However, increasing reactor pressure was actually shrinking the reactor water level and minimizing the chance for flashing in the reference leg.

Following the event, the licensee initiated the calibration of Level Switch (LS) 1B21-N038A (annunciator window E105), 1B21-N038B (annunciator window E105), and 1B21-N024D (annunciator window B509). The following calibration results were obtained:

Inst.	As Found Rx Level Trip (inches)	As Found Rx Level Reset (inches)	As Left Rx Level Trip (inches)	As Left Rx Level Reset (inches)
N038A	24.63 Rejected	34.80	19.40*	25.76*
N038B	21.38	36.52	19.68	28.74
N024D	22.65	33.13	19.26	29.73

Administrative Setpoint	19.4 inches
Technical Specification Setpoint	12.5 inches
Technical Specification Allowable	11.0 inches

*New SOR Switch

The sequence of events are as follows:

Time plus (Fraction of a Second)		Annunciator	Inst.
23:03:01	.707	E105	N038A
	.773	B509	N024D
23:03:02	.187	Channel A1/B1 RPS L3 Alarm	

As shown by the sequence of events and from reviewing the narrow range level recorder (1C34-R608) strip charts, the SOR switches in question followed the sequence of events and the actual reactor level. This further supports the conclusion that reference leg flashing did not occur.

Level switch N038A and N024D share a common condensate pot. The licensee verified that other level instruments sharing the same condensate pot were reading within acceptable limits as compared to level instruments using different condensate pots.

Members of the AIT observed portions of the N038A calibration. The Instrument Mechanics (IM) were knowledgeable of the test procedure and qualified to perform the calibration. The test procedure was clearly written, steps were performed in a logical manner, and the acceptance criteria was well defined. The IM's employed a calibration method that the AIT members had not previously observed in use. The method connected test water bottles and trap to the high and low pressure test connections. The high pressure test bottle was filled with demineralized water. This permitted the purging of the level switch of any entrapped air and permitted the equalizing of the water head that was imposed on the high and low bellow sides of the level switch. As a result, the level switches were being calibrated in a consistent manner. The calibration method was considered by the AIT to be a good practice.

The AIT reviewed the past calibration records for possible calibration trends. The review indicated that SOR drift was random in nature.

The AIT has concluded that the SOR level switches were exhibiting characteristics that were not uncommon to past operating experiences and was not the result of the event.

6. Review of the Licensee's Actions

A. Procedure Review

The AIT reviewed the licensee's special operating procedure, LLP 89-012, Unit 2 shutdown with loss of SAT 242. The procedure was developed by the licensee to place the unit into a hot shutdown condition, in a controlled manner, if shutdown was required because of inability to return the SAT to service. The expiration of the 72 hour Technical Specification limiting condition of operation, associated with the loss of the SAT, would have required the unit to shutdown. The procedure was well developed and contained the requirements of the approved written emergency procedures. The special procedure contained steps to mitigate the potential loss of instruments by providing temporary jumpers to available power supplies that would not normally be available until the recovery phase of the emergency procedures. The licensee then conducted a simulated controlled shutdown on the LaSalle specific simulator. Additionally, the licensee incorporated the lessons learned during the walkdown of the draft procedure on the LaSalle simulator. These actions and the preparation of the procedure indicated strong management involvement and planning.

B. Plant Walkdown

Subsequent to the events, the licensee performed a plant walkdown to determine the status of affected relays and components. The walkdown determined that the relays were not exposed to overcurrent conditions due to the lack of evidence such as trip relays having electrical scarring or carbon buildup. The walkdown also found evidence indicating undervoltage and low voltage conditions existing on busses, such as the process computer undervoltage relay being tripped.

C. Licensee Response to the Unit 1 Scram and Unit 2 SAT Failure

The licensee's management demonstrated conscientious involvement from a safety standpoint during the events. Management conservatively approached the event by declaring an Unusual Event emergency action level even though the Unit 2 unit auxiliary transformer was available and unaffected during the event. Site and corporate management promptly responded onsite to the event and provided sound direction and support during the event recovery. The licensee staff was responsive to the NRC initiatives and cooperative with AIT members throughout the special inspection. In addition, the licensee promptly evaluated the event and determined the root causes associated with the Unit 1 reactor scram, Unit 2 SAT failure and the apparent responses of the individual system components. These actions are considered to have demonstrated strong management involvement.

Prior to the event, both units were running in a steady state condition with minimal activities taking place throughout the plant. As the event started and continued, the NSOs and operation's supervision responded well and in accordance with their training and procedures.

Initial response to the Unit 2 alarms indicated that the unit had scrammed. As the operator quickly reviewed the indications, the unit was determined to have not received a scram signal and that there was a feedwater transient in progress. The NSO's actions addressing the feedwater transient and reduction in power prevented the unit from scramming on low reactor vessel water level.

The Unit 1 NSO correctly responded to the unit scram and recovery. The scram was considered to be unavoidable.

Within five minutes after the Unit 2 SAT tripped, most of the equipment that had tripped or isolated had been reset and/or restarted. Unit 2 was stable at approximately 66% power and Unit 1 was steady in the scram recovery.

The licensee made the appropriate emergency notification with information available to them at the time of the notification.

The AIT attempted to review records relating to testing of the lightning arrester. The licensee indicated that the lightning arresters were tested by CECo Operating Analysis Department (OAD) but the data was not recorded. In addition, acceptance criteria for testing the lightning arrester was not available. The failed arrester was sent to the manufacturer (General Electric) for analysis to determine the failure mechanism. The licensee has committed to make the results available to the NRC. Since large electrical equipment is routinely tested by CECo OAD and testing data is not recorded or maintained, this is considered to be an unresolved item (373/89007-01 and 374/89007-01). A similar problem was previously identified in Section 5.A.

7. Safety Significance of the Events

The AIT reviewed the significance of the two events, the Unit 1 reactor scram and the loss of Unit 2 SAT. The AIT evaluated the conditions of the units against three related accident analyses contained within the LaSalle FSAR; the loss of system auxiliary transformer, the loss of all electrical grid connections (loss of all offsite power) and the Design Bases Accident (DBA). The following considerations were based upon actual unit equipment availability during the events:

- All of the ECCS systems and components were available to both units throughout the events.
- The Primary Containment Isolation Systems (PCIS) for both units were unaffected during the events. Several individual PCIS components, such as reactor building ventilation dampers and reactor water cleanup system isolation valves, had closed during the events on both units from undervoltage or low voltage conditions existing on individual busses. These conditions did not affect the units' ability to mitigate other plant upset conditions.
- No plant upset conditions existed beyond the loss of onsite power for Unit 1 and offsite power for Unit 2.
- Both units' Standby Gas Treatment (SBGT) systems were available to mitigate a potential release from a LOCA.

Based on the above considerations and the actual status of unit equipment (it should be noted that the unit equipment that was affected by the undervoltage or low voltage conditions was reset and returned to operability within five minutes), both events were within the parameters of the three accident analysis and in the judgement of the AIT were determined to have low safety significance.

8. Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, open items, deviations, or violations. Unresolved items disclosed during the inspection are discussed in Paragraphs 5 and 6.

9. Exit Interview (30703)

The inspectors met with licensee representatives (denoted in Paragraph 3) throughout the inspection and evaluation of the events and at the conclusion on March 4, 1989, and summarized the scope and findings of the augmented inspection team's activities. The licensee acknowledged these findings. The inspector 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.

Attachment A

Sequence of Events

Sequence of Events (March 2, 1989):

Central Standard Time

2302:42 Units 1 & 2 main transformer ground alarms indicating a common disturbance on the 345 KV grid.

2302:59 Unit 2 System Auxiliary Transformer (SAT) tripped, initiating automatic bus fast transfer of Unit 2 busses from SAT to the unit auxiliary transformer (UAT). During transfer, Unit 2 UAT trouble and SAT cross winding low voltage alarms received (verifying bus transfer). Unit 2 reactor water cleanup leak detection logic (channels) tripped, resulting in a partial isolation signal. OCBs 4-6 and 1-6 tripped, isolating Unit 2 SAT. 2A and 2B recirculation flow control valve trouble alarm received, indicating low voltage on Bus 235Y-1 during bus transfer. Various trouble alarms and trips associated with undervoltage or low voltage occurred, including 125 VDC Division 3 Bus Under Voltage (automatic start of HPCS diesel generator) and the 2A station air compressor trip.

2303:00 Unit 2 continues to receive various trips and trouble alarms. The duration of the transfer lasted 64 milliseconds. Unit 1 main generator trips on differential, followed by Unit 1 Generator Trip System 1 lockout. Unit 1 initiates automatic bus fast transfer from the UAT to the SAT. During the transfer, the following trips and alarms are received. 1A station air compressor trips (77 milliseconds after generator trip), OCBs 10-11 and 9-10 trip (106 to 114 milliseconds) isolating the Unit 1 UAT, Power Load Unbalance Alarm (120 milliseconds) indicating generator load rejection, turbine control valves Channel A fast closure (144 milliseconds) and Channel B (156 milliseconds), reactor automatic scram (161 milliseconds) and reactor vessel pressure high (942 milliseconds), reactor pressure high-high is not reached during the event.

2303-01 Unit 1 low level (L3) alarm received an Channels A2 and B2.

2303:02 Low level (L3) alarm received an Channels A1 and B1.

2305:03 Unit 1 in scram recovery.
Unit 2 in a vessel level transient.
Unit 2 recirculation system reduced to about 66% reactor power.

about 2308:00 Both units are steady, Unit 1 shutdown and Unit 2 at about 66% power. Systems and alarms have been reset, both station air compressors were restarted. All bus voltages were normal. All spurious alarms have cleared.

CONFIRMATORY ACTION LETTER

MAR 6 1989

CAL-RIII-89-007

Docket No. 50-373
Docket No. 50-374

Commonwealth Edison Company
ATTN: Mr. Cordell Reed
Senior Vice President
Post Office Box 767
Chicago, IL 60690

Gentlemen:

This letter confirms the telephone conversation between E. G. Greenman of this office and D. Galle on March 3, 1989, related to the LaSalle Unit 1 reactor trip and associated equipment problems on LaSalle Unit 2 that occurred on March 2 and 3, 1989. With regard to this event, we understand that you will:

1. Perform an evaluation of the Unit 1 reactor trip as to cause and any systems or components which did not function normally.

2. Perform an evaluation of the Unit 2 equipment that malfunctioned including various isolations and spurious operations.

3. Perform an evaluation of this event including the loss of the Unit 2 system auxiliary transformer and its impact on Unit 1.

4. Identify any equipment that malfunctioned and place such equipment into a quarantine status; this would also include any equipment so designated by the Augmented Inspection Team (AIT) leader.

5. Except as dictated by plant safety, advise the NRC AIT team leader prior to conducting any troubleshooting activities. Such notification should be provided soon enough to allow time for the team leader to assign an inspector to observe activities.

6. Submit to NRC Region III a formal report of your findings and conclusions within 30 days of receipt of this letter.

Throughout this investigative effort, we understand that you will take those actions necessary to ensure that complete documentary evidence of the conditions being examined are maintained and furnished to the NRC's Augmented Inspection Team which was initiated on March 3, 1989.

8903160113 2pp

We further understand that startup of Unit 1 will occur with concurrence of the Regional Administrator or his designee. Issuance of this Confirmatory Action Letter does not preclude the issuance of an order requiring implementation of the above commitments.

None of the actions specified herein should be construed to take precedence over actions which you feel necessary to ensure plant and personnel safety.

Please advise us immediately if your understanding differs from that set forth above.

Sincerely,

Original signed by
A. Bert Davis

A. Bert Davis
Regional Administrator

cc: T. Kovach, Nuclear Licensing Manager
G. J. Diederich, Station Manager
DCD/DCB (RIDS)
Licensing Fee Management Branch
Resident Inspector, RIII
Richard Hubbard
J. W. McCaffrey, Chief, Public Utilities Division
David Rosenblatt, Governor's Office of Consumer Services
J. M. Taylor, EDO
T. E. Murley, NRR
E. L. Jordan, AEOD
J. Lieberman, OE
J. Clifford, EDO
W. Lanning, NRR
F. Miraglia, NRR
M. Virgilio, NRR
G. Holahan, NRR
D. Crutchfield, NRR
S. Varga, NRR
J. Goldberg, OGC
D. Muller, NRR