U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Reports No. 50-373/86007(DRP); 50-374/86008(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: February 13 through March 12, 1986

Inspectors: M. J. Jordan
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4/28/86
Date

Inspection Summary

Inspection on February 13 through March 12, 1986 Reports No. 50-373/86007(DRP); 50-374/86008(DRP))

Areas Inspected: Routine, unannounced inspection conducted by resident inspectors of licensee actions on previous inspection findings; operational safety; surveillance; maintenance; unit trips; region requests; Licensee Event Reports; training; TMI action plan requirement followup; and followup of 10 CFR 50.54(f) request for information. The inspection involved a total of 300 inspector-hours onsite by 6 NRC inspectors including 60 hours onsite during off-shifts.

Results: Of the 10 areas inspected, no violations or deviations were identified in eight areas; two violations were identified in the remaining two areas (failure to follow procedures and have adequate procedures, Paragraph 3 and 4 and failure to perform a Technical Specification required surveillance, Paragraph 4). The licensee continued to experience a problem in recognizing system inoperability. Unit 2 experienced two scrams during the inspection period. The licensee experienced a number of personnel errors and procedural problems.

DETAILS

1. Persons Contacted

*G. J. Diederich, Manager, LaSalle Station
*R. D. Bishop, Services Superintendent
C. E. Sargent, Production Superintendent
D. Berkman, Assistant Superintendent, Technical Services
W. Huntington, Assistant Superintendent, Operations
J. C. Renwick, Assistant Superintendent, Work Planning
*M. Jeisy, Quality Assurance
*P. Manning, Tech Staff Supervisor
T. Hammerich, Assistant Tech Staff Supervisor
W. Sheldon, Assistant Superintendent, Maintenance

The inspectors also talked with and interviewed members of the operations, maintenance, health physics, and instrument and control sections.

*Denotes personnel attending the exit interview held on March 12, 1986.

2 Licensee Action on Previous Inspection Findings (92701)

(Closed) Unresolved Item (374/86003-02(DRP)): The inspector was to evaluate the licensee's actions regarding the 2E12-F008 Reactor Core Isolation Cooling (RCIC) System outboard steam isolation valve. This evaluation was completed as discussed in Paragraph 5.

3. Operational Safety Verification (71707)

The inspector observed control room operations, reviewed applicable logs and conducted discussions with control room operators during the inspection period. The inspector verified the operability of selected emergency systems, reviewed tagout records, and verified proper return to service of affected components. Tours of Units 1 and 2 reactor buildings 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 inspector by observation and direct interview verified that the physical security plan was being implemented in accordance with the station security plan.

The inspector observed plant housekeeping/cleanliness conditions and verified implementation of radiation protection controls.

During the month of February 1986, the inspector walked down the accessible portions of the following systems to verify operability:

Unit 1 and 2 Emergency Diesel Generators
Unit 1 and 2 Hydrogen Recombiners
Unit 1 Divisions I, II, and III 125 Volt Batteries and Switchgear

During this inspection period, Unit 1 remained in a refuel outage with the fuel removed from the vessel. Major evolutions included inservice inspection of primary system components, testing of mechanical snubbers, installation of environmentally qualified electrical components and several other modifications to satisfy license commitments.

Unit 2 continued power operation throughout most of the inspection period.

While returning the Unit 1, Division I, 125 volt DC power supply to normal (procedure LOP-DC-02) on February 17, 1986, the power to buses 111X and 111Y was lost resulting in a partial Group II and a Group IV isolation signal which isolated the Reactor Water Cleanup System, the Recirculation System flow control valves, the reactor building ventilation dampers and automatically started the Standby Gas Treatment Systems. The licensee's investigation could not determine if the root cause of this event was equipment or personnel related. The procedure was repeated and performed satisfactorily. No additional action is considered warranted at this time.

The licensee declared an Unusual Event at 1:40 p.m. on February 19, 1986, when a contractor fell inside the Unit 1 primary containment. Due to the possible extent of injury, licensee personnel elected to transport the injured person to the hospital without removing his protective clothing. Due to the possibility of contamination, the Unusual Event was declared.

Radiological control personnel accompanied the ambulance to the hospital where the protective clothing was removed. No contamination was identified and the Unusual Event was terminated at 3:30 p.m..

While performing a transfer of the "1B" Reactor Protection System bus from normal to the alternate feed on February 25, 1986, a Division 2 Group IV isolation signal was received. The procedure, LOP-RP-04, requires the installation of a jumper in panel 1PA14J to prevent the isolation. Subsequent investigation found that the jumper had fallen off one of the connection points. Licensee personnel consider that this isolation was caused by the type of jumper being utilized. Work requests were initiated to investigate providing different jumpers. This situation is similar to the jumper problem discussed in Paragraph 4.

On March 2, 1986, the licensee reported a Unit 2 Engineered Safety Feature (ESF) isolation for the Reactor Water Cleanup System (RWCU) due to differential flow. After the isolation, the inboard isolation valve was not able to be reopened. The licensee decided to bring the unit down for repair of the valve before the reactor vessel water chemistry exceeded Technical Specification limits which would have required a shutdown. During the shutdown at approximately 7% power, the unit scrammed on a High High Intermediate Range Monitor signal (See Paragraph 6 for Scram).

The investigation of the isolation determined that three valves were left open after performing a backwash on the "A" Filter/Demineralizer (FD) on February 26, 1986. During precoating of the "A" Filter/Demineralizer on March 2, 1986 and while it was being unisolated for return to service, the open valves allowed excess flow through the "A" F/D to the phase separator tank. The excess flow, of approximately 66 gallons per minute (GPM), gave a sufficient differential flow signal out of versus into the reactor, to isolate the system.

The individual who performed the backwash thought the valves were closed because the valve apparently struck the closed stops. A review by the licensee later determined that the valve stops on all three valves were defective such that the operator could not tell when the valve closed. The backwash procedure LOP-RT-05 has a note in the precautions, "Valve position can be verified by orientation of flats on valve stem...." (in order to accomplish this verification, the operator must enter a high radiation area.) The note was put into the procedure because of several previous events on mispositioned valves in this system. LER's 374/85-36, 374/84-36, 374/84-37, and 374/84-61 reported similar events on Unit 2 alone. Unit 1 LER's were not reviewed.

Discussions with the individual who performed the backwash indicated he had been trained on checking the valve flats, if needed, but thought the valve was closed. He had previously entered the room to verify the valve flat position only once or twice since he had been operating the system. Technical Specification 6.2.A states, in part, "Detailed written procedures including applicable checkoff lists covering items listed below shall be prepared, approved, and adhered to for the applicable procedures recommended in Appendix "A" of Regulatory Guide 1.33, Revision 2, February 1978."

Regulatory Guide 1.33, Revision 2, February 1978, Section 4 requires procedures for Startup, Operation, and Shutdown of Safety Related BWR Systems including as Item c., "Reactor Water Cleanup System." The licensee failed to adhere to the procedure for closing the valves on the RWCU System while backwashing the "A" F/D. This is considered a violation (374/86008-01(DRP)).

A followup on the inboard isolation valve for the RWCU system that stuck closed determined the torque switch failed to actuate, and with the thermal overloads bypassed due to a valid differential flow isolation signal, the valve was driven into its seat for approximately eight minutes. This continuous closure signal on the valve motor caused it to become damaged. After verifying no leaks in the system and resetting the isolation signal, the thermal overloads for the motor were found burned up. The thermal overloads were replaced and opening of the valve was attempted. When the valve could not be opened, the unit was shut down. After shutdown, the valve motor and torque switch were replaced and the torque necessary for opening of the valve was checked. The spring pack on the valve limitorque operator was found to be on the high side of the acceptable band according to Limitorque. The valve operator was put back together with the existing spring pack. A replacement spring pack was ordered. The valve was then local leak rate tested, and the system was declared operable. The high spring pack torque had no effect on valve closure. The high spring pack only has an effect on valve opening and, therefore, the safety feature of closure for isolation was considered operable.

The licensee identified some pressure switches for Low Low Set (LLS) on the safety relief valves that failed to actuate during the scram on February 16, 1986. The licensee found the trip setpoint tends to drift upward over a period of time on pressure switches which are not exercised on a frequent basis, such as a monthly functional test and a quarterly calibration. These switches were calibrated every 18 months with no functional testing required between calibrations. The vendor (Static-O-Ring Company) came to the site to witness the functional testing that the licensee accomplished and is evaluating the cause and corrective action. To assure operability of pressure switches in safety related applications, the licensee has increased the exercising of these switches to every 14 days. This item has been referred to Region III for assistance. This item will remain as an open item (373/86007-01; 374/86008-02(DRS)).

4. Monthly Surveillance Observation (61726)

The inspector observed Technical Specifications required surveillance testing and verified for actual activities observed that testing was performed in accordance with adequate procedures, that test instrumentation was calibrated, that limiting conditions for operation were met, that removal and restoration of the affected components were accomplished, that test results conformed with Technical Specifications and procedure requirements and were reviewed by personnel other than the individual directing the test, and that any deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel.

The inspector witnessed portions of the following test activities:

LOS-FP-W2; Weekly Operational Test of the "B" Diesel Fire Pump
LOS-DG-M3; Testing of the 2B Diesel Generator Following Maintenance
LTS-100-35; Local Leak Rate Testing on the Unit 1 RHR Shutdown Cooling Inboard Isolation Valve

No items of concern were identified.

Upon completion of the Scram Discharge Volume Scram functional test, LIS-RD-401 on February 17, 1986, the Unit 2 reactor operator inadvertently placed the reactor mode switch in the "run" position in lieu of "shutdown" resulting in a Group I isolation signal and closure of the main steam isolation valves. Procedure LOP-AA-03 was issued in August 1985 to help prevent this type of actuation. Although this event is considered to be another example of a personnel error, it is considered to be an isolated case of a mistake by an experienced operator. Accordingly, a violation will not be issued.

During the week of February 24, 1986, the inspectors brought to the licensee's attention a potential problem with the method the licensee was using to maintain Unit 2 system operability during snubber testing on Unit 1. Technical Specification (T.S.) 3.7.9 requires that snubbers are to be operable on systems required to be operable depending on the mode of the reactor. The Action Statement for this Technical Specification requires that with one or more snubbers inoperable, within 72 hours, replace or restore inoperable snubbers to operable status and perform an engineering evaluation or declare the associated system inoperable. The licensee was removing and returning snubbers on operable systems using the 72 hour Action Statement to allow them to accomplish the 18 month snubber testing and was not considering system operability. They considered that the 72 hours was established as a low probabilistic time that a seismic event would happen and, therefore, removal and replacement of snubbers on operable systems did not effect operability of the system until the 72 hours expired. The inspector considered, however, that the 72 hours was intended as a reasonable time to allow the licensee to evaluate the effects of finding a snubber damaged while walking through the plant before having to declare a system inoperable.

Using the licensee's interpretation, the utility had planned on removing snubbers from the Unit 2 common systems (hydrogen recombiners and ventilation connection to the Standby Gas Treatment (SBGT) Systems) and not worry about the effect of system operability as long as they were replaced within 72 hours. Unit 2 was at 100% power. The inspector expressed concern over operability of these systems with snubbers removed, and suggested that the licensee should do an engineering analysis to determine how many snubbers could be removed before operability was affected, prior to removal of any snubbers on systems they were considered operable. The licensee believed that the analysis would be too costly because, depending on the mode the plant was in, every safety system would eventually need to be analyzed for snubber removal.

A subsequent review of the snubber testing procedure LTS 500-14 identified under the "Precautions" that snubber removal on operable systems had to be restored within 72 hours before the piping it was on was declared inoperable. Appendix I to the procedure had a list of factors to consider for snubber removal and item 7 was, "Try to select snubbers from systems that are not required to be operable during the refueling outage when testing occurs." The licensee tried to minimize the removal of snubbers from operable systems where possible. When the snubbers were required to be removed from an operable system, the 72 hour time frame for testing was the driving motivation, not necessarily the affect of snubber removal on operability of the system.

On February 27, 1986, the inspector contacted NRR for some assistance on what would be expected from the licensee. NRR agreed that since there were so many snubbers in the system that removal of one or two snubbers from each analyzed subsystem would be acceptable. An analyzed subsystem was where an entire system (i.e. hydrogen recombiner) was broken down into several subsystems or sections that were seismically analyzed separately. One or two snubber removals from each subsystem on required operational systems was the method the licensee intends to use to complete the 18 month required testing.

The inspector had difficulty with this method of testing in that during an outage in the future, if the fuel was not off loaded, then several systems would be required to be operable. This was not the case for the present Unit 1 outage. Using this interpretation, the utility could remove one or two snubbers from each analyzed subsystem for several required operational systems at the same time and not know if the systems were operable or capable of surviving a seismic event. This item needs further review by the NRC. This item will remain as an unresolved item (373/86007-02(DRP)).

On the evening of February 26, 1986, the licensee reported to the inspectors that the interlock was found defeated on the doors for the Unit 2 personnel access to the drywell. While performing the six month surveillance test (LTS-300-6) it was found that both doors to the drywell could have been opened at the same time, defeating the primary containment airlock required by Technical Specification 3.6.1.3. The drywell has been inerted with nitrogen since the unit startup on December 25, 1985 and, therefore, the primary containment airlock had been maintained. The licensee reported that on December 23, 1985, a shift foreman passed through the personnel access and tested the interlock. He did not, however, verify the performance of the test on the surveillance data sheet since it was not performed to meet the surveillance frequency requirements. The licensee was unable to identify who installed the defeat mechanism for the personnel airlock after December 23, 1985. The person who installed the defeat mechanism violated the procedure for installing the airlock interlock defeat mechanism (LOP-PC-5) in that a temporary system change per LAP 240-6 was not initiated. The temporary system change procedure is the same procedure used for temporary jumper installations in the plant. No violations were issued because the event was reported by the licensee correctly and the criteria of 10 CFR 2, Appendix C were met for not issuing a violation. The licensee is changing the drywell close out (after outage) procedure LOP-DW-1 to require a verification that the defeat mechanism has been removed by verifying the interlock works in accordance with LTS-300-6. The licensee will also place a sign on both Unit 1 and 2 airlocks in the area of the defeat mechanism to identify that the defeat mechanism should only be installed with a temporary system change in accordance with LAP 240-6.

At 11:55 a.m. on February 26, 1986, while performing the 18 month Injection Test, LOS-SC-R1, on the Unit 1 Standby Liquid Control (SBLC) System, the "1B" Emergency Diesel Generator automatically started on a false low (-50 inches) reactor water level signal. Subsequent licensee investigation determined that a pressure surge in the SBLC injection line created a perturbation in the reactor vessel instrumentation panel 1H22-P005. The injection and instrumentation piping share a common reactor vessel connection. The pressure perturbation caused the High Pressure Core Spray (HPCS) actuation instruments to sense a false low reactor vessel water level signal which would normally start the HPCS pump and its emergency power supply, the "1B" Diesel Generator. The diesel started, but the HPCS pump did not since it was out-of-service for maintenance.

Additional licensee and inspector investigation determined that the cause of the SBLC system pressure spike was that the system downstream of the explosive valve had not been filled and vented prior to operation. The procedure to replace the explosive valve (W/R 55965) did not ensure that the system piping was filled and vented. The surveillance procedure, LOS-SC-R1, only fills the piping upstream of the explosive valves. This event is similar in nature to a scram caused by a hydrostatic test in July 1985, as noted in Licensee Event Report (LER) 85-55.

Technical Specification 6.2 requires, in part, that procedures for preventive and corrective maintenance operations which could have an effect on the safety of the facility be prepared, approved, and adhered to. 10 CFR 50 Appendix B Criterion V requires procedures to be appropriate to the circumstances.

Contrary to the above, the procedure utilized to replace the SBLC system explosive valve failed to assure that the system piping downstream of the valve was properly filled and vented resulting in an unnecessary actuation of the "1B" Emergency Diesel Generator. This is considered to be a violation (373/86007-03(DRP)).

On February 27, 1986, the licensee reported that the Unit 1 conductivity sample surveillance, which was required by Technical Specifications, was missed on February 18, 1986. Investigation by the licensee identified that the Reactor Water Cleanup (RWCU) and Reactor Recirculation (RR) Systems had been taken out-of-service on February 18 for unit outage work which made the continuous conductivity monitor in the control room inoperable. Technical Specification 4.4.4.C requires that when the continuous monitor is inoperable, a sample shall be obtained every 24 hours in any mode other than modes 1, 2, and 3 which require a 4 hour sample. To be conservative, the Chemistry Department had been taking water samples every 24 hours for the chloride Technical Specification 4.4.4.b surveillance which was required on a 72 hour sample frequency. The technician reported to the chemistry foreman on February 18 that he was unable to take a sample because the RWCU and RR systems were shut down. The chemistry foreman, becoming aware of the systems being shut down, logged this in on the surveillance sheet, Page 10, in procedure LAP 1800-4. This sheet required a conductivity sample to be read "every 24 hours when the continuous conductivity monitor is inoperable for up to 31 days."

The chemistry foreman failed to recognize that with the RR and RWCU systems shutdown, the continuous monitoring for conductivity was inoperable. The inspector talked to the chemistry foreman on March 6th and verified that he knew the system and was well aware that with the RR and RWCU systems shut down the continuous monitor was not working. He did not relate that to a need for increased sampling required by Technical Specifications and the requirements of LAP 1800-4. The chemistry foreman stated he had contacted the Unit 1 shift foreman to determine when the RWCU and RR systems would be returned to service so he could get the 72 hour sample for chlorine, and was told that the RWCU should be back on February 19. On February 19 when the RWCU was not back in service, the chemistry foreman had the chemistry technician take a dip sample from atop the open reactor vessel. The foreman told the NRC inspector that had the shift foreman told him the continuous monitor was "inoperable" his mind would have been jogged to take the 24 hour sample required by the surveillance sheets of LAP 1800-4.

The chemistry foreman also stated he was busy the morning of February 18 reviewing three days of data taken after the holiday on February 17th and Unit 2 was being returned from a scram on the 16th which required samples to be taken and he just did not relate RWCU shutdown with "inoperable" continuous conductivity monitor. The Operations Department failed to declare the continuous monitor inoperable on February 18, 1986. The system was declared inoperable on February 22, 1986, 4 days after the RWCU system was taken out-of-service. The system was returned to operability on March 4, 1986, within the allowed time clock of 31 days in Technical Specifications. The chemistry foreman had not been trained on Technical Specifications; however, he was aware that an "inoperable" continuous conductivity monitor means an increase in surveillance sampling.

A review of the chemistry surveillance procedure LAP 1800-4 identified an error in the procedure in that the 24 hour sample would only be required in "Modes 4 and 5", where Technical Specifications state at all times other than Modes 1, 2, and 3 which includes Modes 4 and 5 as well as when the reactor is defueled. Thus, since the fuel was taken out of the vessel prior to February 18, the reactor was not in Modes 1, 2, 3, 4, or 5, but, water chemistry samples should have been taken. The chemistry foreman thought Unit 1 was in Condition 5 on February 18. A review of the daily surveillance sheets for operations (LOS-AA-D1) indicated Modes 4 and 5 for applicability of Technical Specification 4.4.4 in lieu of "all times." Since the unit was not in modes 4 and 5, the sheets had been marked "N/A".

A review of this event identified several personnel errors including failures of the operations department to declare the continuous monitor inoperable on February 18 and log it as such in the unit log or on the time clock display board as required by the unit operator log procedure LAP-220-2, and failure to take the required sample by LAP 1800-4. While not affecting the situation described above, two procedures were identified with errors which could mislead personnel. Failure to perform the surveillance requirements of Technical Specification 4.4.4.C is considered to be a violation (373/86007-04(DRP)).

While performing a routine low low water level containment isolation response time test LIS-PC-15 on Unit 1, a Division 2 Group II and a Group IV isolation signal were received at 12:40 p.m. on March 4, 1986, which automatically isolated the reactor building ventilation system, started both trains of Standby Gas Treatment (SBGT), and isolated miscellaneous containment penetrations such as containment monitoring, drywell humidity monitoring, and the recirculation system flow control valves. The isolation signal was caused by personnel error. The Instrument Technician was installing a jumper to prevent the reactor building ventilation isolation and SBGT initiation when he inadvertently grounded the temporary jumper. This blew a fuse and deenergized the control power, resulting in the actuation of Group II and Group IV isolation including initiation of SBGT. Discussion with the maintenance staff indicated that this personnel error could reasonably have been prevented by a wiring system change that would improve jumper installation and removal. For routine surveillances where jumpers are installed the licensee agreed, where needed, to change the type of connector, and/or move the connection point to prevent recurrence of this event. No violation was issued for failure to follow procedure because the licensee action met the enforcement policy identified in 10 CFR 2, Appendix C. Tracking of the corrective action will be via open item (373/86007-05(DRP)).

5. Monthly Maintenance Observation (62703)

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

The following items were considered during this review: the limiting conditions for operation were met while components or systems were removed from service; approvals were obtained prior to initiating the work; activities were accomplished using approved procedures and were inspected as applicable; functional testing and/or calibrations were performed prior to returning components or systems to service; quality control records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; radiological controls were implemented; and, fire prevention controls were implemented.

Work requests were reviewed to determine status of outstanding jobs and to assure that priority is assigned to safety related equipment maintenance which may affect system performance.

The following maintenance activities were observed/reviewed:

The inspector evaluated the licensee's actions regarding the 2E12-F008 Reactor Core Isolation Cooling (RCIC) System outboard steam isolation valve. This valve had failed to close from the control room switch on February 6, 1986. This valve had been inspected during the fall 1985 outage to confirm proper wiring of the limitorque operator. The NRC identified inadequacies in the documentation of the licensee's inspection as noted in Report No. 374/85040. As a result the licensee issued a Work Request (L55706) in January 1986, to reinspect the valve operator wiring. The valve subsequently developed a packing leak and failed to properly cycle (close) on February 6, 1986 when operated from the control room. Work requests were issued to troubleshoot the failure to operate and repair the packing leak. The wiring reinspection, operator troubleshooting and packing repairs were completed on February 8, 1986. The licensee's review of the troubleshooting results; however, failed to identify a reason as to why the valve had not operated on February 6, 1986. The licensee initiated another Work Request (L56143) on February 18, 1986, to inspect the control room control switch for the valve. Contact points 5 and 6 of the control switch were found to be operating intermittently. The switch was repaired and the system was returned to service on February 21, 1986.

The licensee's and inspector evaluation determined that no Technical Specification or system operability requirements were violated by the previously described sequence of events. The inspector did, however, discuss the apparent administrative and Quality Assurance weaknesses with the licensee. The licensee's reviews of the wiring inspection failed to identify the inadequate documentation until notified by the NRC in January 1986. In addition, upon completion of the troubleshooting on February 8, 1986, the licensee still had not identified a root cause of the valve's failure to operate on February 6, 1986. This evaluation did not result in the initiation of additional troubleshooting until February 18, 1986, which indicates a lack of aggressive management attention to problems.

On March 11, 1986, the licensee on Unit 2 reported that the switchs for the high level isolation on the High Pressure Core Spray System (HPCS) and Reactor Core Isolation Cooling (RCIC) System were required to be Environmentally Qualified (EQ) and appeared not to be. On March 12, the licensee determined that the installed switches were environmentally qualified. They were investigating the reason the installed switches were not changed as was originally planned prior to November 30, 1985. The resident inspector will follow up on this item. This item will remain as an Unresolved Item (374/86008-03(DRP)).

6. Unit Trips (93702)

At 3:03 p.m. on February 16, 1986, Unit 2 scrammed from approximately 100% power following a turbine generator load reject and turbine trip. Due to an area ice storm, offsite power from line L0101 was lost opening circuit breakers OCB 1-9 and OCB 9-10. One phase on breaker OCB 1-9 failed to open causing a phase differential fault to be felt by the Unit 2 output breakers resulting in the unit generator load reject. The "2 East" main transformer deluge system actuated due to the sensed phase differential. Six safety relief valves initially opened to control pressure. The unit operator manually initiated the Reactor Core Isolation Cooling (RCIC) System to help control pressure and level. Two suppression pool to drywell vacuum breakers cycled due to the safety relief valves cycling. Reactor vessel water level dropped to zero inches. Following the shutdown, the licensee noted that the "A" Lo-Lo set logic did not actuate for the Automatic Depressurization System (ADS). Subsequent investigation found a potential generic problem with the actuation switches. As discussed in Paragraph 3, the NRC is pursuing this issue. The unit was restarted on February 17, 1986.

Unit 2 again scrammed from 8% power during a planned shutdown on March 2, 1986. The unit was being shutdown for a drywell entry to repair the 2G33-F001 Reactor Water Cleanup (RWCU) System inboard isolation valve. Due to feedwater level control problems, the unit scrammed on high neutron flux (Intermediate Range) when the motor driven reactor feed pump was restarted and injected cool water to the vessel. The unit was restarted on March 5, 1986. Level control during a plant startup or shutdown has been a problem at LaSalle since initial startup. Current procedure is to require an equipment operator to manually adjust a gate valve as directed by the unit operator. The probability of this event reoccurring remains high until the licensee initiates corrective action such as installing a bypass valve around the feedwater control valve. Improvements to the feedwater system to provide better level control during start-ups and shutdowns will be tracked as an open item (373/86007-06; 374/86008-04(DRP)).

7. Region Requests (92705)

On February 19, 1985, the inspector was requested to investigate the licensee's explosive valves installed and in stores for the Standby Liquid Control (SBLC) System as followup to an event at Vermont Yankee. The explosive valves had failed to fire during a routine 18 month surveillance and yet, the circuit continuity light in the control room indicated that the circuit was ready for operation. The valves failed to operate at Vermont Yankee due to a factory miswired firing circuit inside the valve. Preliminary investigation by the valve manufacturer, Conax Corporation, indicated that suspect valves had been shipped to LaSalle.

The inspector reviewed the licensee's installation procedures and records for the valves installed:

Work Request	System Valve	Date Installed
L50332	1A	07/85
L29917	1B	12/83
L28582	2A	12/83
L47577	2B	03/85

The inspector also reviewed the Vendor's Manual for the valves, the receipt inspection records (Purchase Order 740552) and monitored the licensee's ongoing actions to test fire the installed "1B" explosive valve. The records for installation of the 1A, 2A, and 2B valves provided a detailed continuity verification procedure that conformed to the vendor manual. The procedure was sufficiently detailed that miswired valves should have been readily identified prior to installation. In addition, one of the fifteen valves received on Purchase Order 740552 was successfully test fired by the licensee during receipt inspection on September 20, 1983. The fifteen valves received at LaSalle were identified as follows:

Purchase Order:	740552
Part No:	1532-159-01
Ordered:	03/16/83
Shipped:	08/25/83
Received:	09/13/83
Batch:	HEC 82L009-003
Primer Chamber:	Part No. 1621-240-01, Serial Numbers 641 thru 655

The valve installed in the 1B loop was successfully test fired on February 26, 1986. The remaining four valves stored by the licensee were checked for proper continuity (Work Request L56337) and all found to be properly wired. In addition, the inspector reviewed the wiring circuit for the control room continuity light (Drawings 1E14209AB and 1E24209AB) for Units 1 and 2 and discussed the surveillance procedure (LOS-SC-R1) and results of the test of the 1B valve with the licensee. The licensee's surveillance procedure verifies that the continuity light extinguishes upon firing of the explosive valve. The licensee also confirmed that the continuity light would not remain energized with a miswired explosive valve. The inspector noted that the licensee's drawings incorrectly showed the wiring bridge connections from pins 1 to 2 and 3 to 4 in lieu of the required connection from pins 1 to 4 and 2 to 3. The licensee confirmed the correct as installed configuration and initiated drawing change requests to correct the drawings. It was also noted that 4 of the original 15 valves were shipped to Hope Creek. In summary, all valves currently installed and stored at LaSalle are considered to be satisfactory.

8. Licensee Event Reports (92700)

Through direct observations, discussions with licensee personnel, and review of records, the following Licensee Event Reports (LERs) 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.

373/86001-00 - The "B" Control Room HVAC System Ammonia Detector Tripped Causing an ESF Actuation of the Control Room Dampers. This was caused by a master fault due to either a misaligned loading gate assembly from vibration of the vacuum pump or a dirty photo cell. Final corrective action is being tracked in conjunction with the 10 CFR 50.54(f) corrective action plan.

373/86002-00 - Main Steam Safety Relief Valves E, H, and U Fail to Meet Setpoint Tolerance Specified by Technical Specifications. In accordance with the In-Service Inspection Program, all of Unit 1 safety/relief valves were tested for set pressure. Valves E, H, and U did not meet the nameplate set pressure and were reset to the safety setpoints. The licensee agreed to revise the corrective action on this LER to address the causes identified in the LER. The NRC identified the incomplete LER evaluation.

373/86003-00 - Missed Surveillance of Reactor Water pH Due to Personnel Error. This error was due to poor communications between Rad/Chem personnel. Final corrective action to be tracked in conjunction with the 10 CFR 50.54(f) corrective action plan.

373/86004-00 - Control Room Ventilation Actuation in Recirculation Mode Due to Ammonia Detector Chemcassette Tape Break. The tape carriage mechanism was replaced and detector returned to service.

374/85032-01 - Unit Leak Detection Division 1 and 2 Residual Heat Removal Differential Temperature Not Operable. The supplement included the Station Nuclear Engineering Department (SNED) review findings that confirmed the cause code in this revision was changed to B (Design or Installation Deficiency) and a supplemental report will be issued to reflect the correct original cause code E (Quality Assurance Deficiency).

374/86001-00 - Diesel Generator (D/G) Output Breaker Failure to Close Due to Faulty Contacts. LER issued due to D/G valid test failure. A supplemental report will be issued when the licensee's evaluation of the failure is completed.

374/86002-00 - Erratic Operation of Reactor Core Isolation Valve. An unresolved item was issued in Inspection Report 374/86003. Refer to Paragraph 5 for additional discussion.

9. Training (41400)

The inspector, through discussions with personnel and a review of training records, evaluated the licensee's training program for operations and maintenance personnel to determine whether the general knowledge of the individuals was sufficient for their assigned tasks.

Specific areas reviewed are identified in Paragraphs 4 and 5. No items of concern were identified.

10. TMI Action Plan Requirement Followup (25565)

Closed (Open Item 373/81000-74 and 374/81000-61): TMI Action Plan Item I.A.2.1 - Immediate Upgrading of Reactor Operator and Senior Reactor Operator Training and Qualifications. In Section 13.2 and 22 of the LaSalle Safety Evaluation Report (SER), the staff concluded that the training program established by the licensee at the time of the reviews met the requirements of this item. A review of the LaSalle Administrative Procedures LAP-600-6, "Preparation for NRC Exam Administration," and NUREG 1021, "Operator Licensing Examiner Standards," by the inspector verified that the upgrades mentioned in this item have been implemented.

Closed (Open Item 373/81000-145 and 374/81000-62): TMI Action Plan Item I.C.2 - Shift Relief and Turnover Procedures. The staff raised several concerns regarding this item. The item concerning shift technical advisor turnover functions was closed in Inspection Report 82-006. A review of LaSalle Administrative Procedure LAP-200-3, "Shift Change," and LaSalle Operating Surveillance LOS-AA-S1, "Shiftly Surveillance", revealed that the remaining concerns have been adequately addressed.

Closed (Open Item 373/81000-92 and 374/81000-64): TMI Action Plan Item II.E.4.1 - Dedicated Hydrogen Penetrations. LaSalle has two permanently installed post-loss-of coolant accident recombiners each taking suction and discharging through dedicated penetrations and safety grade piping and valves. Similarly, the containment purge system uses dedicated penetrations and safety grade piping and valves. Both systems meet redundancy and single failure requirements of Criteria 54 and 56 of the General Design Criteria. In addition, the recombiners are remote manually controlled from the main control room. Therefore, the staff concluded that LaSalle complies with the provisions of Item II.E.4.1 of TMI-2 action plan as stated in Chapter 22 of the SER.

Closed (Open Item 373/8100085 and 374/81000-63): TMI Action Plan Item II.B.1-Reactor Coolant System Vents. In Section 11.B.1 of the LaSalle Safety Evaluation Report, the staff concluded that the design met the requirements of this item contingent upon valve position indication in the control room. The inspector determined that said indication has been installed. The inspector also determined that procedures for use of the various vents were in place.

11. Followup of 10 CFR 50.54(f) Request for Information (71707, 92701)

By letter dated November 22, 1985, NRC concerns related to the overall operation of the LaSalle County Station were transmitted to the licensee with a request for information in accordance with 10 CFR 50.54(f) regarding how the licensee was going to address those concerns. On December 23, 1985, Commonwealth Edison responded in a letter from Mr. Cordell Reed to Mr. J. G. Keppler, and outlined a program where each of the areas of concern would be addressed. A second response was submitted on February 4, 1986, which further delineated the licensee's proposed actions and included a more detailed schedule when each action would be completed.

The inspector performed a review of the following areas to verify the licensee's commitments as outlined in their responses and the adequacy of the program implementation.

a. Modifications

The inspector performed a review of the licensee's modification program in selected areas including program upgrades in relation to the licensee's response to the NRC's 10 CFR 50.54(f) letter. It was found through discussions with plant personnel and review of appropriate documentation that a Modification Review Committee (MRC) has been formed at LaSalle Station and is composed entirely of site upper management with authority to determine categorization, prioritization, and scheduling of all modifications onsite. The MRC also has responsibility for determining if proposed modifications are actually needed.

Following formation of the MRC, a complete review of modifications outstanding at the time was conducted. From this, 67 modifications were found to be not needed and were subsequently cancelled. The inspector performed a review of these cancelled modifications and following resolution of a number of questions, agreed with the licensee's evaluation on all but one of the modifications involved, to date.

The remaining modification (1-1-84-038) involved installation of a new sightglass to give a visual indication of Standby Liquid Control System (SBLC) storage tank level. The current sightglass does not give an accurate enough indication of tank level, so presently, the licensee is using a plumbob arrangement as a physical verification of tank level. This system is acceptable if the conversion from the plumbob depth reading can be accurately correlated to tank volume. The licensee has agreed to make available for review, the analysis that supports the conversion formula in use at the station. This is an open item pending completion of the inspectors' review of the analysis. (373/86007-07(DRP))

The inspector performed a review of the following modification packages and ascertained that the associated documentation was adequate.

M1-1-82-305	CRD Pump Trip/Low Pressure Scram During Reactor Low Pressure Conditions
M1-1-84-026	Primary Containment Vent and Purge Valve Replacement

b. Scram Reduction Program

The organization and implementation of the Scram Reduction Committee is outlined in LaSalle Administrative Procedure LAP-200-8. The committee members consist of the Production Superintendent, Assistant Superintendent Operations, Assistant Superintendent Maintenance, ATSS Operations group leader and Nuclear Safety representative. From the scram history review, root cause trending is used as a bases towards scram reduction. The licensee's review of the past conduct of operations revealed no concerns or recommendations in this area. A review of conduct of operations is done after a scram to possibly minimize further scrams. A review of the Reactor Protection System (RPS) surveillance testing by the licensee found the present method of surveillance testing to be adequate.

Channel redundancy is one area under consideration by the licensee to reduce the number of turbine trips. Other alternatives identified were: (1) to change the monitoring system, which could include a massive turbine overhaul. (2) per General Electric recommendation, install a time delay to avoid vibration spike trips. A large portion of the licensee's turbine trips can be attributed to these vibration spikes. The feasibility/cost study has been completed and is currently under review by the committee.

Instrument line hydraulic transients resulting in Reactor Protection System (RPS) trips is also considered a problem area by the licensee. The RPS trips generally occur when an Instrument Mechanic (IM) is valving in/out an instrument line. Alternatives identified by the committee included using a five valve manifold consisting of stack disc valves or moving the reference leg connection to dampen the pressure spike. This second alternative may or may not be acceptable pending Station Nuclear Engineering Department (SNED) and Sargent & Lundy review of NRC Generic Letter 84-23. Generic Letter 84-23 discusses reference leg overheating and minimizing the length of the reference leg in the drywell. There is currently a modification issued to shorten and relocate the sensing lines inside the drywell for accident conditions.

The licensee is currently testing the stack disc valves for possible replacement of the current needle valves. The licensee currently feels that the stack disc valve design will best alleviate the problems associated with valving in/out of the needle valves.

c. Reduction of ESF Actuations

Guidance for the task of reducing ESF actuations is contained in the Charter to the Committee letter from the plant manager to department heads. The task force committee consist of the following members: Technical Staff Supervisor, Assistant Superintendent of Technical Services, SNED representative, Instrument Staff Assistant and Senior Reactor Operator representative. The task force originally planned to meet monthly, but did not hold a meeting in January or February. The task force did meet in March and may meet weekly due to the recent increase of ESF Actuations. There is no procedure for the task force to implement as guidance. A review of ESF actuations is done concurrently with the LER writeup within the required 30 day reporting time period.

Tracking and trending of ESF actuations is done by sorting Licensee Event Reports (LERs) via the computer system. This enables the licensee to track LERs by system, type of failure, cause code, etc.. Through trending of LERs, the licensee has identified three problem areas. The problem areas identified were Reactor Water Cleanup (RWCU) delta flow isolation, RWCU inlet/outlet valves of the filter demineralizer, and Chlorine detectors. The licensee also plans to upgrade the Ammonia detector equipment but has not made a commitment to do so to date.

The licensee's commitment to the RWCU delta-flow calculation data modification did not meet the installation completion date of February 15, 1986. The Engineering Analysis for the modification (M-1-2-85-032) was done onsite and was approved by SNED by the projected completion date. The delay in the completion of the modification is due to Instrument Mechanic department review. The IM department is questioning whether the associated instrumentation can physically be recalibrated. The recalibration of instrumentation is to allow the system to compensate for delta flow changes during startup or shutdown of the plant. The modification also changes the control room alarm for RWCU isolation from the present 45 second time delay. Currently, the alarm annunciates at 45 seconds simultaneous with isolation of the system. The modification would allow the alarm to alert the operator at 0 seconds, allowing time to notify anyone working on the system and avoid a possible isolation after 45 seconds. The new projected completion date for Unit 1 is May 3, 1986, and Unit 2 is scheduled for Fall 1986.

The Chlorine detector modification has been cancelled. A technical specifications change request was submitted to NRR for relief from the Chlorine detector requirements.

The RWCU valve replacement modification has also been cancelled. Instead of replacing the valves, the licensee is planning to purchase spare parts from the original vender and will qualify the spare parts onsite for the existing valves. The licensee will replace only the valves that have given the most trouble.

d. Radiation Protection Performance

The inspector accompanied the master electrician into the plant and observed the installation of one of the new local audible alarms on a high radiation door. The alarm has a unique high pitched sound and should assist in identifying doors being left open. This appears to be a major step in trying to reduce high rad doors being left open.

12. Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, violations, or deviations. Unresolved items disclosed during the inspection are discussed in Paragraphs 4 and 5.

13. Open Items

Open items are matters which have been discussed with the licensee, which will be reviewed further by the inspector, and which involve some action on the part of the NRC or licensee or both. Open items disclosed during the inspection are discussed in Paragraphs 3, 4, 6, and 11.

14. Exit Interview (30703)

The inspectors 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 inspector also discussed the likely informational content 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.