U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Reports No. 50-373/89026(DRP); 50-374/89025(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, Illinois

Inspection Conducted: Dece[illegible] 8 through January 16, 1990

Inspectors: R. Lanksbury
R. Kopriva
D. Jones
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Approved By: J. M. Hinds, Jr., ~~Chief~~ 02.06.90
Reactor Projects Section 1A Date

Inspection Summary

Inspection from December 8 through January 16, 1990 (Reports No. 50-373/89026 (DRP); 50-374/89025(DRP))

Areas Inspected: Routine, unannounced safety inspection by the resident and region based inspectors of licensee action on previously identified items; operational safety; surveillance; maintenance; licensee event reports; ESF system walkdown; training; security; report review; IDNS site inspection; onsite followup of events at operating power reactors; TMI action plan requirement followup; emergency preparedness; startup following a refueling; TIs and leak rate test results.

Results: Of the fourteen areas inspected, no violations were identified. In the remaining area, one violation was identified (see paragraph 4.b) regarding adherence to Technical Specifications. The containment integrated leak rate test results were acceptable and the containment passed in both the as-found and as-left conditions. There was a typographical error in the Unit 1 Technical Specifications in which the operators were to place the operable channel in a tripped position. They placed the inoperable channel in a tripped position, which was technically correct and in agreement with the Unit 2 Technical Specifications, but not in accordance with the Unit 1 Technical Specifications. Aggravating this was the fact that members of the licensee's staff, including management, had been aware of this error for some time, but had failed to take action to correct it. Due to the licensee's response and corrective actions, the violation will not require a response.

During this inspection period, the licensee demonstrated weaknesses, other than that noted above, in the quality of drywell walkdowns prior to a startup (refer to paragraph 3.d), control of contractors (refer to paragraph 5.a), and operation's resolution of a problem with the C SRM (refer to paragraph 15.b). However, with regard to the first three of these weaknesses management demonstrated a strength in aggressive and timely resolution to the problem as well as corrective actions to preclude repetition. Additional strengths were also noted in the licensee's resolution of debris in the suppression pool and in the operators' performance during the Unit 1 startup.

DETAILS

1. Persons Contacted

   *G. J. Diederich, Manager, LaSalle Station
   *W. R. Huntington, Technical Superintendent
   *J. C. Renwick, Production Superintendent
   J. V. Schmeltz, Assistant Superintendent, Operations
   J. Walkington, Services Director
   *T. A. Hammerich, Regulatory Assurance Supervisor
   W. E. Sheldon, Assistant Superintendent, Maintenance
   *W. Betourne, Quality Assurance Supervisor
   *W. J. Marcis, Site BWR Engineering Supervisor
   *J. Borm, Quality Assurance
   J. Roman, Resident Engineer, Illinois Department of Nuclear Safety
   J. Glover, Production Services General Office ILRT Coordinator
   J. Reters, ILRT Lead Test Engineer

   *Denotes personnel attending the exit interview on January 22, 1990.

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

2. Licensee Action on Previously Identified Items (92701)

   (Closed) Violation (No. 373/87027-02; No. 374/87026-02): Failure of the licensee to require the need for fire brigade assistance upon receipt of a fire alarm on the control room annunciator panel. By letter dated July 11, 1989, W. E. Morgan to A. B. Davis, the licensee provided a proposed method for when the fire brigade would be required to assemble immediately upon receipt of a fire alarm. The letter outlined specific areas, and the applicable conditions, under which this would occur. By letter dated November 6, 1989, J. C. Bradfute to T. J. Kovach, the NRC provided a safety evaluation of the licensee's plan for responding to fire alarms and concluded the response was adequate to close the issue. This item is closed.

3. Operational Safety Verification (71707)

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

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

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

c. On December 16, 1989, at approximately 5:30 a.m. (CST), the licensee discovered the Unit 2 250 VDC battery room below 65 degrees F. The limit for battery operability is a battery temperature of 65 degrees F. Battery pilot cell temperatures were taken and found to be 58 degrees F and 60 degrees F respectively. At 6:15 a.m., the 250 VDC system and the Reactor Core Isolation Cooling (RCIC) system were declared inoperable. The RCIC system was declared inoperable because the 250 VDC system is the emergency power supply for the RCIC systems motor operated valves. At 9:20 a.m., the required Emergency Notification System (ENS) notification was made for the RCIC system being inoperable. The licensee's investigation into the cause of the low battery room temperature revealed that an outside air damper was not fully closed. This allowed intake of the unseasonably cold outside air. The damper was wired in the fully closed position and heaters were placed in the battery room to bring the temperature up. On December 17, after completion of surveillance tests of the batteries and return of the battery temperatures to above 65 degrees F, the 250 VDC battery system and the RCIC system were declared operable.

d. On January 2, 1990, the inspectors performed a walkdown of the Unit 1 drywell. This walkdown was performed after the licensee's final closeout inspection had been performed but while some unplanned work under the reactor vessel was being completed. This inspection resulted in the identification of a number of issues requiring resolution prior to startup. The majority of the issues involved the removal of trash, equipment and tools. The licensee's review of the list of items identified by the inspectors indicated that some of them had been identified during the closeout inspection. The licensee had already planned to correct these items prior to startup. The inspectors expressed their concerns over the thoroughness of the final closeout inspections. The licensee indicated that the need to perform a thorough job during the closeout inspections had been discussed with the responsible individual.

No violations or deviations were identified in this area.

4. Monthly Surveillance Observation (61726)

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

The inspectors witnessed portions of the following test activities:

LIS-NR-405	Unit 2 Rod Block Monitor Functional Test
LIS-RI-301	Unit 1 Steamline High Flow Reactor Core Isolation Cooling (RCIC) Isolation Functional Test
LOS-DG-M2	Unit 2 A Diesel Generator Operability Test
LTS-1100-14	Shutdown Margin Subcritical Demonstration
LTS-1100-1	Shutdown Margin Test

a. On December 26, 1989, at 5:15 p.m. (CST), the licensee was performing surveillance procedure LIS-RI-412, Unit 2 Reactor Vessel High Water Level RCIC Turbine Trip Functional Test. At 8:30 p.m., it was discovered that the reactor vessel hi water level switch 2B21-N101B had tripped and would not reset. The switch was left in the tripped condition and the RCIC system declared inoperable. A 14 day Limiting Condition of Operation (LCO) time clock was started and an A priority work request initiated. The resident inspector was notified and an Emergency Notification System (ENS) phone call made at 9:52 p.m. On December 27, 1989, at 7:30 a.m., surveillance procedure LIS-RI-212, Unit 2 Reactor Vessel High Water Level RCIC Turbine Trip Calibration, was completed satisfactorily for the new switch. At 11:47 a.m., LIS-RI-412 was completed with acceptable results and at 12:35 p.m., the Unit 2 RCIC system was declared operable. Unit 2 was operating at or near 100% power at the time of this event. The resident inspectors followed the licensee's actions during the event.

b. On January 5, 1990, at approximately 1:30 a.m., during the performance of a routine station surveillance the licensee determined that the Static-O-Ring (SOR) switch (1E31-N012AA) which provides the Division 1 Residual Heat Removal (RHR) high suction flow isolation signal was inoperable due to a blown diaphragm. At 2:15 a.m., the licensee placed Division 1 in a tripped condition. No valve motion took place as a result of this action because the RHR system had already been shutdown for the unit startup. At 2:33 a.m., the licensee made an ENS notification. Subsequent to this, during a review of the licensee's actions by the inspector, it was identified that Unit 1 Technical Specifications (TS) 3.3.2.b required the licensee to place the OPERABLE channel in the tripped condition. The OPERABLE channel was Division 2, not Division 1 that had been tripped. At the time this was identified the reactor had a pressure of greater than 135 psig and, therefore, a trip signal for RHR shutdown cooling was already in for both divisions. TS 3.3.2.b requires that the trip be taken within one hour. The Division 2 isolation signal for the reactor being greater than 135 psig came in at 4:51 a.m., or two hours and 21 minutes past the one hour time. Subsequent investigation revealed that the Unit 2 TS's read that the INOPERABLE channel was to be placed in the tripped condition. Further review of this matter, including review of the Safety Evaluation Report (SER) and consultation with NRR, determined that Unit 1 TS's should read that the INOPERABLE channel should be placed in the tripped condition. In this particular case there was no safety significance to the licensee's action. The operators involved in this event apparently did not read in detail what the TS action was: The same basic statement correctly appears several places in the TSs and is also in the Unit 2 TSs in multiple places. The operators knew what it was supposed to say and read that into the words when they looked at this particular statement.

On January 5, the licensee replaced the defective 1E31-N012AA switch and at 5:00 p.m. declared the new switch operable after completion of testing.

Unit 1 Technical Specifications 3.3.2.b require that with the number of OPERABLE channels less than one, place the operable channel in a tripped condition within one hour.

Contrary to the above, on January 5, 1990, at 1:30 a.m. when the SOR switch was determined inoperable, the number of operable channels was less than one and at 2:15 p.m., the licensee placed the INOPERABLE channel in the tripped condition instead of tripping the operable channel. At 4:51 a.m. all channels were tripped due to the reactor having exceeded the high pressure setpoint.

This is a violation (No. 373/89026-01).

The licensee's investigation determined that the cause of the violation stemmed from a typographical error in the Unit 1 Technical Specifications. Review of the SER basis for the Technical Specification, and concurrence with NRR supported the licensee's conclusion of the error being typographical. As corrective actions the licensee performed the following: (1) contacted the NRR licensing Project Manager (LPM) for LaSalle for short term clarification; (2) wrote an interpretation/clarification of Technical Specification 3.3.2.b to document action to be taken by the operating shift personnel after consulting the LPM; (3) documented the conversation with the LPM; (4) put in place a mechanism (form) to be used by personnel when a problem with Technical Specifications is noted. The form documents the concern and ensures that action will be taken to resolve the concern; (5) implemented the revised (corrected) Technical Specification page. This violation meets the criteria of 10 CFR 2, Appendix C, Section V.A.; consequently, no Notice of Violation will be issued, and this matter is considered closed.

This violation was aggravated by the fact that members of the licensee's staff, including management, were apparently aware of the error and had known of its existence for some time (the error appears to have existed since 1985). These individuals failed to bring this error to the attention of their licensing group so that it could be corrected. In the past the licensee had no formal mechanism in place to allow errors of this nature to be documented and transmitted to the cognizant individuals for obtaining changes. As noted above, as part of the corrective actions to the violation, the licensee has implemented a program that should accomplish this. The need to comply with the Technical Specifications, except when the provisions of 10 CFR 50.54x apply, has been discussed with the licensee as well as the methods (emergency change, waiver of compliance, discretionary enforcement, etc.) available to obtain Technical Specifications changes.

No deviations were identified in this area. However, one violation, for which a Notice of Violation was not issued, was identified in this area.

5. Monthly Maintenance Observation (62703)

Station maintenance activities of systems and components listed below, including safety-related systems, 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. Portions of the following maintenance item were observed during the inspection period:

Unit 1 A Turbine Driven Feedwater Pump and Turbine Maintenance

a. During Unit 1 startup on January 9, 1990, the main turbine was brought to rated speed (1800 rpm) in preparation for synchronizing and placing the Unit 1 Main Generator on line. At 1:30 p.m. the Unit 1 Nuclear Station Operator (NSO) attempted to flash the Unit 1 Main Generator field by closing the Main Generator Field Breaker. No generator field voltage or output voltage was observed at this time.

At 9:10 p.m. the Unit 1 Main Power Transformer disconnects were opened and the Unit 1 345KV ring bus was re-established while troubleshooting of the failure to excite the main generator was in progress. During troubleshooting and inspection of the Unit 1 Main Generator exciter the three phases which direct AC power from the exciter to the field rectifier were found disconnected.

On January 10, at 12:26 a.m., the Unit 1 Turbine Generator was tripped in preparation to take it out of service to allow termination of the exciter AC bus sections. At 2:15 a.m. the Unit 1 Main Turbine Generator was out of service and work was started to terminate the exciter AC bus sections. At 5:40 a.m. the Main Generator Exciter AC bus section were terminated and the Main Turbine Generator out of service was cleared. At 9:30 a.m. the Unit 1 Main Turbine was again brought to rated speed and at 10:10 a.m. the Unit 1 Main Generator was synchronized to the grid and loaded without any further problems.

During the investigation of this problem the inspectors found that on September 17, 1989, work was authorized by operating supervision to disassemble the Unit 1 Main Generator for removal of the rotor to replace the damaged Unit 2 Main Generator rotor. During the disassembly of the Unit 1 Main Generator Exciter, the three phases of the AC bus sections were unbolted and turned to allow them to be rebolted in place to prevent them from interfering with the exciter housing removal. The connections at the top of the exciter housing are difficult to see without climbing to the top of the exciter.

On December 12, 1989, the Maintenance/Modification Contractor (MMC) commenced terminating the Main Generator Alternator Exciter cables per the Nuclear Station Work Request. During the installation of the DC bus section, the Engineering and Construction (ENC) Supervisor arrived to observe the work in progress and assumed that all three AC bus section phases were in place, since from the floor the turned bus bars appeared to be connected. No communication between the afternoon shift MMC crew and the day shift MMC crew took place which questioned whether the AC bus sections were complete or not.

The Unit 1 Main Generator reassembly was completed and the post maintenance checklist was reviewed by the Shift Engineer (SE) on December 27, 1989. No final walkdown of the completed work was found documented in the work package by the MMC.

This event delayed the synchronization of the Unit 1 main generator to the system grid for approximately 14 hours. Because this event only involved the main generator the safety significance of this event was minimal and at no time was the safe operation of the plant in jeopardy.

No violations or deviations were identified in this area.

6. Licensee Event Reports Followup (90712, 92700)

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

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

No. 373/89025-00 Loss of Bus 142Y Due to Closing Switchgear Door and Jarring Relays

No. 373/89026-00 Inadvertent Primary Containment Isolation Actuation Due to Inadequate Logic Setup During Modification Installation

No. 373/89027-00 Primary Containment Isolation During Surveillance Testing Due to Burned Out Annunciator Window Light Bulbs

No. 374/89006-01 Setpoint Drift of Low Level Confirmed Automatic Depressurization System Permissive Switch

No. 374/89016-00 Reactor Water Cleanup Isolation on High Differential Temperature Due to Thermocouple Failure

No. 374/89017-00 High Pressure Core Spray Pump Minimum Flow Bypass Differential Pressure Switch Found Above Reject Limit Due to Setpoint Drift

No. 373/89024-00 Unsealed Openings in Control Room Due to Original Construction

b. The following report of a nonroutine event involved violations of regulatory requirements. This report is considered closed. Event closure is being tracked by the associated violation.

No. 373/89028-00 Shutdown Cooling Outboard Isolation Valve Automatic Closure Due to Miscommunication Error During Instrument Surveillance (Violation 373/89023-01e).

No violations or deviations were identified in this area.

7. ESF System Walkdown (71707)

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

Unit 2 A Emergency Diesel Generator
Unit 1 Standby Liquid Control System

No violations or deviations were identified in this area.

8. Training (71707)

The inspector, through discussions with personnel, 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.

In the areas examined by the inspector, no items of concern were identified.

No violations or deviations were identified in this area.

9. Security (71707)

The licensee's security activities were observed by the inspectors during routine facility tours and during the inspectors' site arrivals and departures. Observations included the security personnel's performance associated with access control, security checks, and surveillance activities, and focused on the adequacy of security staffing, the security response (compensatory measures), and the security staff's attentiveness and thoroughness. The security force's performance in these areas appeared satisfactory.

No violations or deviations were identified in this area.

10. Report Review (90713)

During the inspection period, the inspectors reviewed the licensee's Monthly Operating Report for December. The inspectors confirmed that the information provided met the requirements of Technical Specification 6.6.A.5 and Regulatory Guide 1.16.

11. IDNS Site Inspection (71707)

On December 14, 1989, members of the Illinois Department of Nuclear Safety (IDNS) staff arrived at the LaSalle County Nuclear Station for the purpose of inspecting the licensee's radiation waste shipments. An entrance meeting was held at 8:30 a.m. after which the IDNS members and licensee personnel performed an inspection of a truck as it prepared to leave the site. The inspection team then proceeded to the radiation waste truck bay to observe the licensee's procedure for preparing radwaste shipments for site departure. The IDNS resident engineer and NRC resident inspector accompanied the IDNS members on their tour. This inspection was a training session for the IDNS members. Actual IDNS inspections are expected to increase in the upcoming years. This site visit covered site familiarization and establishment of appropriate site personnel contacts for future communications. The IDNS members held an exit at 1:15 p.m. followed by site departure.

12. Onsite Followup of Events at Operating Power Reactors (93702)

During a preparatory Integrated Leak Rate Test (ILRT) inspection of the Unit 1 Suppression Pool (SP), the licensee observed some foreign material in the water. The inspection was made from one of the SP entry hatches. The observed materials appeared to be plastic bags and a piece of plywood with a piece of 2x4 lumber attached. The wood was on edge coming out of the water and appeared to be wedged in the structural steel. The licensee sent a diver into the SP to inspect for and recover any debris. This attempt was unsuccessful due to limited mobility of the diver and restricted visibility due to the high turbidity of the SP water. Subsequent to this the licensee developed an action plan to recover any foreign material in the SP.

On December 26, 1989, the SP water level was lowered to where it had been during the original inspection (approximately 10 feet below normal) and another inspection of the SP was made. This inspection was made by lowering a small inflatable rubber boat and two licensee inspectors into the SP. The inspection included the entire circumference of the SP plus any areas between the structural steel and the downcomers into which the boat could gain access. The wood that was originally reported to be present was not located. However, the licensee reported that they believe that a steel anchor plate, located very close to the location where the wood was reported as being, was probably mistaken from a distance as being wood. The following is a list of what the licensee reported as having been retrieved from the SP:

- 1 36"x48" poly rad bag (removed from downcomer supports)
- 1 12"x12" poly rad bag (removed from downcomer supports)
- 12"x12" poly rad bags (removed from the water)
- 1 10"x10"x10" triangular piece of plastic (appeared to be from orange rain gear, removed from the water)
- 1 plastic pen cap (removed from the water)
- Approximately 20' of 3/8" plastic polyflow tubing with brass fittings (removed from the water)
- Approximately 40' of 1/4" plastic polyflow tubing with two valves and fittings (removed from the water)

Because some areas around the structural steel could not be inspected and because the high turbidity level of the SP water prevented inspection below the water surface, the possibility existed that additional debris remained that was not retrieved. The licensee performed an onsite review of this matter in addition to attempting to determine the most likely pathways for the material to have gotten into the SP. With regard to the latter, the licensee could not positively determine how the material got into the SP, however, the tubing may have fallen from the drywell through the downcomers and the remaining materials were hypothesized to most likely have been introduced through the Primary Containment Vent and Purge system penetrations. With regard to the safety consequences, should any foreign material still exist in the SP, the licensee considered the probability of its migrating to the Emergency Core Cooling Systems (ECCS's) suction strainers, the location of the strainers in the SP, the fact that each ECCS pump has its own strainer, the 100% oversized design of the strainers (could be blocked up to 50%), and that any degradation on pump suction flow would be detected during routine surveillance testing. They concluded after consideration of the above, that there was no reasonable threat to the performance of the ECCS pumps. The inspectors reviewed the licensee's evaluation of this event and concluded that reasonable assurance existed that the performance of the ECCS pumps would not be jeopardized.

The licensee is reviewing future corrective actions as a result of this event. These include:

a. An evaluation of methods to improve control over materials which could be lost in the SP.

b. Determine the source of the high turbidity in the SP water.

c. Evaluate the possibility of clearing up the water inventory in the SP.

d. Conduct future inspection of the SP to ensure that no foreign materials are present which would impact ECCS system performance.

These corrective actions apply to both units and the licensee plans to incorporate them, as appropriate, into future outage plans.

No violations or deviations were identified in this area.

13. TMI Action Plan Requirement Followup (25565)

(Closed) TMI Item II.K.3.16b (Units 1 and 2): This item required the licensee to perform an evaluation of reduction of challenges and failures of relief valves. This item was previously reviewed in Inspection Reports No. 50-373/89021 and No. 50-374/89021. At that time the inspectors had been unable to verify the submittal of, and acceptance of, the BWR Owners Group study on this matter by NRR. Subsequently, NRR, by letter dated December 12, 1989, J. O. Bradfute to T. J. Kovach, re-issued a safety evaluation (SE) that addressed this issue and was applicable to LaSalle County Station, Units 1 and 2. The SE hao previously been transmitted to Commmonwealth Edison Company (CECo) in connection with Dresden and Quad Cities but not to LaSalle. However, the Safety Evaluation Report (SER), NUREG-0519, indicated that the issue was addressed prior to the licensing of LaSalle Unit 1 and that the NRC requirements were satisfied for this item. Based upon the above, TMI Action Item II.K.3.16b (Units 1 and 2) is closed.

(Closed) TMI Item II.K.3.28 (Units 1 and 2): This item required the licensee to perform an evaluation of the qualification of automatic depressurization system (ADS) valve accumulators. This item was previously reviewed in Inspection Reports No. 50-373/89021 and No. 50-374/89021. At that time the inspectors were unable to verify NRR acceptance of the BWR Owners Group evaluation submitted by the licensee and the subsequent request for additional information (RAI) response made by the licensee. By letter dated December 5, 1989, J. O. Bradfute to J. W. Craig, NRR indicated that, subsequent to the RAI, 1982 NRC internal documentation indicates that a surveillance requirement should be inserted in the LaSalle Technical Specifications in order to verify periodically that the ADS air supply would be available when needed. This surveillance requirement was added and obviated the need to condition the LaSalle Unit 1 licensee as originally indicated in the SER (NUREG-0519). They concluded on the basis of the documentation that this issue is closed. Based upon the above, TMI Action Item II.K.3.28 (Units 1 and 2) is closed.

No violations or deviations were identified in this area.

14. Emergency Preparedness (71707)

On December 31, 1989, at approximately 9:05 a.m. (CST), the licensee determined that the Process Computer had stalled. With the Process Computer not functioning, the licensee had lost offsite dose assessment capability and core monitoring capability. A two hour timeclock and a 24 hour timeclock, respectively, were entered. At the time of this event, Unit 2 was at approximately 85% power and ramping up and Unit 1 was shutdown for a refueling/maintenance outage. The power increase was terminated pending the return of the Process Computer. At 11:03 a.m., the licensee determined that the Process Computer would not be operable prior to the two hour timeclock expiring. At 11:09 a.m., an Emergency Notification System (ENS) notification was made to report the loss of offsite dose assessment capability. The cause of the loss of the Process Computer was determined to be a software problem. The problem was corrected and at 1:00 p.m. the Process Computer was returned to operability.

No violations or deviations were identified in this area.

15. Startup Following a Refueling (71711)

a. On January 4, 1990, at approximately 7:15 p.m. (CST), the licensee placed the Unit 1 mode switch in Startup and commenced performance of shutdown margin testing. At 9:15 p.m., the Nuclear Station Operators commenced pulling control rods. The reactor was declared critical at 11:36 p.m. with a period of 290 seconds. The resident inspectors were in the control room for portions of the unit startup, witnessing the licensee's actions. At the time of startup, Unit 1 had been shutdown for 111 days (since September 15, 1989) in a refueling/maintenance outage. Some of the major work accomplished during the outage included the completion of 54 modifications, decontamination of the reactor recirculation piping, reactor recirculation pump discharge valve modifications, drywell cooling modification, and overhaul of the main turbine including the use of the Unit 2 rotor in the main generator (the Unit 1 rotor was used to replace the Unit 2 rotor after an event involving water intrusion in the generator).

b. On January 6, 1990, at approximately 10:30 a.m., the licensee placed the Mode Switch in RUN and at 11:08 p.m., the main turbine was rolled up to 1800 rpm. On January 7, at approximately 2:45 a.m., the licensee tripped the main turbine after discovering that one of the main disconnects in the switchyard would not close. Subsequent to this, the licensee received a hydrogen panel trouble alarm. The hydrogen panel alarm was traced to a high oil level in the generator casing drain. The licensee drained a quantity of oil, estimated at less than two gallons, from the casing drain. After consultation with their corporate office, the licensee decided to take the unit back down to where they could close the Main Steam Isolation Valves (MSIV's) in order to allow opening the generator up to inspect for the cause of the oil leakage. At 6:15 p.m., control rod insertion was begun and at 7:20 p.m. the Mode Switch was placed in STARTUP. At 9:10 p.m., the main steam lines were isolated. When the Source Range Monitor's (SRM's) were inserted, the licensee determined that the C SRM was not functioning correctly and declared it inoperable. As part of the original startup, the licensee was also performing the Local Leak Rate Test (LLRT) of the drywell personnel access hatch door seals. The licensee determined that the inner door seal was not holding the required pressure and that, therefore, the inner door was inoperable.

   The licensee investigated the cause of the oil intrusion into the generator and determined that the apparent cause was due to a defective oil temperature switch that had allowed the oil temperature to rise slightly above the vendors recommended maximum temperature and that, therefore, the reduced viscosity of the oil had allowed it to migrate down the shaft past the seals. The licensee also determined that the drywell inner door seal was defective and replaced the seal. The subsequent LLRT of the drywell hatch was successful. The licensee attempted to repair the C SRM but was unable to determine the cause of the failure. Because the TS's allow one SRM to be inoperable, the licensee decided to resume the startup without the C SRM being operable. On January 8, at 11:20 p.m., the Mode Switch was placed in STARTUP and on January 9, at 2:30 a.m., the licensee commenced pulling control rods. At 4:55 a.m., Unit 1 was critical with a period of 110 seconds.

c. On January 9, 1990, at approximately 9:30 p.m. (CST), the licensee was proceeding with their Unit 1 startup. The Nuclear Station Operation (NSO) retracted the A Intermediate Range Monitor (IRM) and received the full out indication. However, the detector was still indicating a reading on range nine. The A IRM was then placed in the degraded equipment log. The licensee's inspection of the A IRM revealed that the IRM had retracted approximately two feet when it came in contact with a section of Traversing Incore Probe (TIP) tubing (location 10-57). When contact was made, the A IRM stopped, but then the drive motor stripped a gear and continued until it reached its full out limit switch, thus giving the indicated full out signal. Further inspection of the TIP tubing revealed that a support bracket for TIP tubing 10-57 had broken at the weld and the tubing was damaged.

Reviews of maintenance records revealed that TIP tube 10-57 had been replaced during the outage. The cause of the interference is not known for sure however one possibility is that the replacement tubing was not formed correctly or, due to some other reason, the tubing was not in the correct location such that it interfered with the withdrawal of the IRM. Because of this, the TIP tubing prevented the retraction of the IRM. The IMs replaced the damaged TIP tubing and verified that it would not interfere with any other instrumentation.

Due to the lengthy repair time that would be required to correct the IRM drive motor problem, the licensee elected to continue with the unit startup with the A IRM being inoperable. The remaining seven IRM's were all functioning properly. The A IRM problem is to be corrected during the next Unit 1 outage of sufficient duration.

The outage was delayed approximately 30 days from its original estimated completion date. This delay appears to be due to a number of reasons. The licensee utilized a new main contractor for this outage. The new contractor was not brought on site until approximately one month prior to the start of the outage. The licensee apparently misjudged the amount of time it would take the contractor to become fully acclimated to their work climate. Shortly after the outage started the licensee's internal Quality Assurance (QA) organization found a problem that resulted in a self-imposed stop work order being imposed. This delayed a significant portion of the outage work. The main generator rotor swap that resulted from the Unit 2 generator water intrusion event also appeared to have caused delays at the end of the outage in testing of balance-of-plant (BOP) equipment. In addition, minor equipment problems at the end of the outage also appeared to cause delays. The above problems, combined with what appears to have been an unrealistic outage schedule even without these problems, combined to cause the schedule slippage.

No violations or deviations were identified in this area.

16. Temporary Instructions (25027)

(Open) TI 2500/27 - "Inspection Requirements For NRC Compliance With Bulletin 87-02, Fastener Testing To Determine Conformance With Applicable Material Specifications"

The purpose of this instruction was to provide guidance in evaluating the adequacy of certain licensee's root cause analysis and the implementation of corrective actions in response to NRC Bulletin 87-02.

The sample results submitted by the licensee in response to Bulletin 87-02 indicated that four of 13 safety-related items had failed the testing. This sample was smaller than requested (20 were originally requested) because at the time it represented all that was available. In response to this Temporary Instruction (TI) the inspector accompanied the licensee and made additional selections consisting of 11 safety-related (SR) fasteners (studs capscrews, nuts, and bolts) and 15 non-safety-related (NSR) hex nuts. The 15 NSR hex nuts were taken solely because the licensee wanted to verify that a previous sample that reported one nut as being too soft was an isolated case. This proved to be the case since all fifteen hex nuts passed. The 11 SR fasteners were taken in order to bring the total population of SR fasteners tested above the minimum requirements of Bulletin 87-02. With the exception of one bolt and nut and one stud, all of the SR fasteners tested passed. The stud that did not pass was 1¼" - 8x8", A193, Grade B7. It passed all chemistry tests but failed the tensile test. The results of this test indicated that it was less than 2% below the minimum required. The licensee has evaluated this and considers that the small degree of deviation would not effect the integrity of the material. For the bolt and nut that were tested, however, no specification as to material was made. The licensee is pursuing resolution of this matter.

The licensee has evaluated the deviations from the various standards and considers these to be within that normally expected. They believe that the discrepancies found do not represent examples of product substitution or counterfeiting. The licensee's response to Bulletin 87-02, W. E. Morgan's letter to A. B. Davis dated January 12, 1988, provided how the activities of their Quality Assurance (QA) and Quality Control (QC) organizations related to the control of purchased fasteners. This involvement does not include testing of the purchased fasteners but rather relies on physical inspection and confirmation of receipt of certifying paperwork from the vendor combined with periodic audits of the vendor and their QA program.

This item remains open pending the licensee's resolution of the lack of a material specification for the SR nut and bolt and the submittal of the test results from all of the samples taken in this round of testing.

No violations or deviations were identified in this area.

17. Leak Rate Test Results Evaluation (70323)

a. Methodology Review

As part of the containment integrated leak rate test (CILRT) data analysis, conversion of data from units of standard cubic feet/hour (scfh) to weight percent/ day (wt%/day) was required. The inspector noted that the licensee included in this conversion a temperature correction factor. The inspector reviewed the licensee's calculations and found that in all cases the results were more conservative than the standard conversion formula used throughout the industry.

b. CILRT Data Evaluation

A 6 1/3 hour CILRT was performed during December 23 & 24, 1989, at 54.3 psia following satisfactory completion of the required temperature stabilization period. Data was collected every 10 minutes. The inspector independently evaluated leak rate data using BN-TOP-1 total time formulas to verify the licensee's calculations of the leak rate and instrument performance. There was good agreement between the inspector's and licensee's results as indicated by the following summary (units are in weight percent per day).

Measurement	Licensee	Inspector
Leak rate measured during CILRT (Lam)	0.2078	0.208
Lam at upper 95% confidence level	0.263	0.263

Appendix J acceptance criteria at 95% UCL: $\leq$ 0.75 La = $\leq$ 0.476 wt%/day.

c. Supplemental Test Data Evaluation

After the satisfactory completion of the CILRT, a known leakage rate of 6.52 scfm, equivalent to 6.44 wt%/day was induced. Data was collected and analyzed by the licensee every 10 minutes. The inspector independently evaluated leak rate calculations using the data submitted by the licensee, to verify the licensee's results. After 3.5 hours, the supplemental test was terminated with satisfactory results as indicated by the following summary (units are in wt%/day). The results were stable within the acceptance criteria.

Measurement	Licensee	Inspector
Measured leakage rate, Lc, during supplemental test	0.821	0.821
Induced leakage rate, Lo	0.674	0.644
Lc - (Lo + Lam)	0.061	0.032

Appendix J acceptance criteria $-0.159 < [Lc - (Lo + Lam)] \leq 0.159$

d. CILRT Valve Lineup Penalties

Due to valve configurations which deviated from the ideal penetration valve lineup requirements for the CILRT, the results of LLRTs for such penetrations must be added as a penalty to Lam at the 95% UCL. The following penalties were added using the "minimum pathway leakage" method:

Penetration (System)	Local Leak Rate Test Value (Units are in SCFH)
M-7 (Residual Heat Removal Shutdown Cooling Suction)	1.58
M-15 (Reactor Core Isolation Cooling (RCIC) Steam Supply)	0.74
M-16 (Reactor Building Cooling Water (RBCCW) Supply)	0.37
M-17 (RBCCW Return)	0.00
M-22 (Inboard Main Steam Isolation Valve Drain)	2.05
M-25 (Primary Containment Cooling Water (PCCW), Train A, Supply)	1.49
M-26 (PCCW Train B Supply)	2.03
M-27 (PCCW Train A Return)	0.78
M-28 (PCCW Train B Return)	1.30
M-30 (Reactor Water Cleanup Suction)	0.00
M-34 (Standby Liquid Control)	0.00
M-36 (Recirc Loop Sample)	0.42
M-96 (Drywell Equipment Sump)	0.00
M-97 (Drywell Floor Sump)	1.28
M-98 (Drywell Equipment Sump Cooling)	1.00
(Emergency Core Cooling System / RCIC - Worst Division)	7.04
Unit 1 Hydrogen Recombiner	5.13
Feedwater Line, Train A	7.95
Total Type C Leakage Penalty:	33.16 SCFH

The licensee calculated that this was equivalent to 0.057 wt%/day.

After taking these local penalties into account, the final upper 95% confidence value for containment leakage is equal to 0.320 wt%/day, which is within the acceptable value of $\leq$ 0.476 wt%/day.

e. As-Found Condition of Containment

The as-found condition is the condition of the containment at the beginning of the outage prior to any repairs or adjustments to the containment boundary. The inspector reviewed the licensee's summary of the containment penetration LLRTs (Type B and C) performed prior to the CILRT in order to determine the amount of leakage rate improvement due to RAs. Based on the results reviewed, the inspector determined that the amount of the leakage improvement prior to the CILRT equalled 72.71 scfh, or the equivalent of 0.125 wt%/day. Based on this, the final containment leakage rate, at the 95% UCL, was 0.445 wt%/day.

The containment is considered to have passed the as-found periodic CILRT.

No violations or deviations were identified.

18. Violations For Which A "Notice of Violation" Will Not Be Issued

The NRC uses the Notice of Violation as a standard method for formalizing the existence of a violation of a legally binding requirement. However, because the NRC wants to encourage and support licensees' initiatives for self-identification and correction of problems, the NRC will not generally issue a Notice of Violation for a violation that meets the requirements set forth in 10 CFR 2, Appendix C, Section V.A. A violation of regulatory requirements identified during the inspection for which a Notice of Violation will not be issued is discussed in Paragraph 4b.

19. 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 inspectors also discussed the likely informational contents of the inspection report with regard to documents or processes reviewed by the inspector during the inspection. The licensee did not identify any such documents or processes as proprietary.