U.S. NUCLEAR REGULATORY COMMISSION

REGION III

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Licensee:	Commonwealth Edison Company
Facility:	LaSalle County Station, Units 1 and 2
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Dates:	October 29 through December 17, 1999
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EXECUTIVE SUMMARY

LaSalle County Station, Units 1 and 2
NRC Inspection Report 50-373/99022(DRP); 50-374/99022(DRP)

This inspection report included aspects of licensee operations, maintenance, engineering and plant support. The report covers a 7-week period of inspection conducted by the resident staff.

Plant Operations

- Overall, the performance of operations department personnel during plant operation at power was good. However, in one instance, operator logs were not accurate and this was not identified by licensed operators during shift turnover reviews. (Section O1.1)

- A number of human performance errors occurred during Unit 1 refueling outage activities. These errors were due, in large part, to the failure of personnel to self-check or independently verify that the correct equipment was being operated, or was being removed for maintenance. (Section O1.2)

- Although the closeout of the Unit 1 drywell was well-controlled, suppression pool closeout activities were not rigorously controlled. (Section O1.2)

- The conduct of heavy load movements during the Unit 1 refueling outage occurred in a slow and controlled manner and were performed well. (Section O1.2)

- Adequate controls for the handling and storage of fuel during the Unit 1 refueling outage were delineated in station procedures and the vast majority of fuel movement activities were adequately conducted. However, due to a lack of attention-to-detail and a failure to adequately conduct self-checking and independent verifications, four fuel positioning errors occurred. (Section O1.3)

- Operator actions to address a Unit 2 electro-hydraulic control transient, which included action to manually scram the reactor, was good. All equipment responded as required and the plant was placed in a stable condition. One error regarding the verification of plant parameters against Technical Specification limits was observed. (Section O1.4)

- Unit 1 and Unit 2 restart activities were conducted in a well-controlled and deliberate manner. Although some minor deficiencies, such as the assignment of responsibilities for controlling reactor vessel level and determining criticality, were observed during the Unit 2 startup, licensee actions to address these concerns were effective as demonstrated by Unit 1 startup observations. (Section O1.5)

- An error in the thermal power computer calculation used for Unit 1 and Unit 2 allowed Unit 1 to exceed the licensed thermal power limit (3323 megawatts thermal) by up to 0.14 percent and Unit 2 by up to 0.21 percent. (Section O1.6)

- Licensee preparations for cold weather were adequate. (Section O1.7)

- During Unit 1 refueling outage L1R08, licensee personnel failed to bypass local power range monitors (LPRMs) when the associated LPRM fuses were removed. This resulted in incorrect inputs to the average power range monitors which rendered them inoperable. One Non-Cited violation was identified. (Section O8.1)

Maintenance

- Observed surveillance activities were satisfactory overall and met Technical Specification requirements. Although some procedure deficiencies and documentation errors were identified, these errors were minor in nature and did not impact the surveillance activities or results. (Section M1.1)

Engineering

- Jet pump modification activities were performed in a satisfactory manner. Engineering reviews addressed the appropriate recirculation system safety functions. Remote visual inspection techniques properly measured riser-to-jet pump gap dimensions. (Section E2.1)

- During quarterly surveillance testing of the 2A residual heat removal service water pump, the licensee determined that pump differential pressure was within the inservice testing required action range. Subsequent investigation revealed a weakness in the equipment trending process when it was discovered that engineering personnel had failed to identify a previous step change in pump differential pressure performance. (Section E2.2)

Plant Support

- The licensee failed to control a high radiation area in accordance with Technical Specification requirements. One Non-Cited violation was identified. (Section R1.1)

- Compensatory fire watches during the Unit 1 refueling outage were performed in a satisfactory manner. During a walkdown of potential fire hazards, the inspectors identified a lack of station Fire Marshall involvement in a turbine-driven reactor feedwater pump oil leak. (Section F1.1)

Report Details

Summary of Plant Status

During this inspection period, Unit 1 completed refueling outage L1R08 and synchronized to the grid on November 22. Unit 2 operated at 100 percent power until November 16, when a manual reactor scram was inserted in response to an electro-hydraulic control system transient. Following a 3-day outage to effect repairs, Unit 2 was restarted and synchronized to the grid on November 19.

I. Operations

O1 Conduct of Operations

O1.1 General Power Operation Observations

a. Inspection Scope (71707)

The inspectors conducted frequent reviews of plant operations at power. These reviews included observations of control room and in-plant evolutions, shift turnovers, operability decisions, and log keeping.

b. Observations and Findings

Inspector observation of operators during operations at power during the inspection period was for the most part without concern. Good three-way communication, good turnover of plant conditions, consistent panel monitoring, and timely response to alarms and other unexpected conditions was observed. However, some deficiencies were identified.

On November 26, 1999, the inspectors observed a number of control rod display alarm lights with blank (unlabeled) indicators. These alarm lights served to inform operators of control rod conditions such as accumulator trouble or whether a control rod was fully inserted or fully withdrawn. The inspectors discussed this observation with the operators who indicated that this problem was due to the difficulty in removing the covers to replace light bulbs which resulted in the lens covers breaking without a replacement lens with the correct lettering. The problem was further exacerbated since the indication bulbs frequently burned out. The licensee generated Problem Identification Form (PIF) L1999-05854 to enter this problem into the corrective action program.

While reviewing Unit 1 control room logs, the inspectors identified an entry at 1:43 p.m. on December 8 which stated that LaSalle Operating Surveillance (LOS) ZZ-W3, "Indoor Oil Separator Oil Level Determinations," had been performed "satisfactory" even though access to all sampling points was not available. The entry should have stated that LOS-ZZ-W3 had been performed with portions "unsatisfactory". The inspectors brought this to the attention of the unit supervisor who corrected the error. The observation was an attention-to-detail log keeping error that at least four licensed operators had failed to identify during pre-shift log reviews. A similar log error was identified by the inspectors on October 10, 1999, and was discussed in Section O1.1 of Inspection Report 50-373/99018(DRP); 50-374/99018(DRP). The licensee generated PIF L1999-06043 to enter this issue into the corrective action program.

c. Conclusions

Overall, the inspectors concluded that performance of operations department personnel during plant operation at power was good. However, in one instance, operator logs were not accurate and this was not identified by licensed operators during shift turnover reviews.

O1.2 Refueling Outage L1R08 Observations

a. Inspection Scope (71707)

The inspectors conducted frequent reviews of Unit 1 plant operations while shutdown for refueling outage L1R08. These reviews included observations of control room and in-plant evolutions.

b. Observations and Findings

Human Performance-Related Events

During the inspection period, a number of human performance-related events occurred during Unit 1 refueling outage L1R08.

On October 30, 1999, work package 980123260-02 for work to be performed on reactor building ventilation damper 1VR01YA was walked down and a pre-job brief was held with the maintenance crew. During the walkdown and brief, the incorrect damper was identified (1VR02YA) and maintenance on this damper was conducted. On November 2, during post-maintenance walkdowns, electrical maintenance workers identified that maintenance had been performed on the incorrect damper.

A prompt investigation was performed which determined that the supervisor who performed the pre-job walkdown and crew briefing failed to verify the correct damper to be worked on, but relied upon a perceived familiarity with the location of components in the work area. In addition, the crew failed to independently verify the correct component and accepted the supervisor's direction that the component identified was correct. The safety significance of this event was minimal since the work on the incorrect damper was within a pre-established out-of-service boundary.

On November 1, 1999, during re-installation of snubber MS04-1245S following functional testing, licensee personnel identified that the incorrect snubber had been removed and tested. A prompt investigation was performed which determined that the root cause for the event was a lack of attention-to-detail and the failure of the first line supervisor and maintenance crew to verify the correct component for removal. The safety significance of the event was minimal since the snubber which was inappropriately removed from the main steam system was not required to support any dead load and the main steam system was not required to be operable.

On November 3, 1999, during preparations to remove control rod drive (CRD) 06-19 for refurbishment, the undervessel crew identified that the CRD in this location had not been de-torqued as required. Further investigation identified that the CRD in location 06-23, which was not scheduled for removal, had been de-torqued instead. A prompt investigation was performed which determined that the root cause for the event was a failure of the technicians performing the work to properly self-check and verify that the correct CRD was identified for removal.

On November 5, 1999, following the completion of a Unit 1 modification, a Group IV isolation occurred during the removal of an out-of-service. This resulted in the closure of the Unit 2 reactor building ventilation containment isolation dampers and automatic initiation of the standby gas treatment system. A prompt investigation determined that the root cause was an out-of-service removal procedure which failed to adequately prescribe the sequence of actions necessary to reset the primary containment isolation logic. In addition, this evolution was not categorized as a high risk activity as appropriate. Corrective actions included revising the work package and out-of-service to provide the proper sequence and re-enforcing site standards for selection of high risk evolutions.

During a review of this event, the inspectors identified that Step B.1.22 of LaSalle Abnormal Operating Procedure (LOA) VR-201, "Unit 2 Switchgear Heat Removal System Abnormal," Revision 2, referenced incorrect steps (19 and 20 vice 20 and 21) for restarting a second set of reactor building ventilation fans. Although this procedure was used to recover from the event, licensee personnel failed to identify that this procedure was inadequate and submit a procedure change request to correct the error until after identification by the inspectors. A similar problem was subsequently identified in Unit 1 procedure LOA-VR-101, Revision 3. This failure constitutes a violation of minor significance and is not subject to formal enforcement action. The licensee generated PIF L1999-05411 to enter this issue into the corrective action program.

On November 19, 1999, the licensee identified that one of four Unit 1 reactor vessel water level instruments had been valved incorrectly. The instrument rack root valves were found lock wired closed when they should have been lock wired open. Maintenance had been performed on the reactor vessel water level system during the refueling outage. Instrument maintenance technicians failed to properly position and verify the positions of the level transmitter isolation valves following the maintenance. In addition, three different technicians failed to either correctly position or verify the status of the isolation valves during subsequent activities and system lineup checks. This failure constitutes a violation of minor significance and is not subject to formal enforcement action. The licensee generated PIF L1999-05761 to enter this issue into the corrective action program.

As discussed in Section O1.3, four human performance events related to the mis-positioning of fuel bundles in the spent fuel pool and reactor vessel also occurred.

Drywell and Suppression Pool Closeout Observations

The inspectors reviewed documentation associated with the Unit 1 drywell closeout inspection and conducted an independent walkdown of the Unit 1 drywell. During the walkdown, debris which included a flashlight, a 6-inch by 6-inch piece of plywood, a 2-foot long piece of aluminum, and other smaller items were identified for removal. However, the items were neither individually or collectively significant enough to warrant further efforts to identify additional debris in the drywell.

The inspectors also requested documentation regarding the closeout of the suppression pool. In response, the licensee provided videotapes and documentation of the underwater as-found inspection of the suppression pool. The inspectors reviewed these tapes and documentation and identified that no as-left closeout documentation existed. In addition, although all of the downcomer T-quencher bases were documented to exhibit major coating blistering, this condition had not been identified for resolution prior to Unit 1 restart.

The inspectors discussed this issue with licensee personnel who identified that the T-quencher base plate material was American Society of Testing and Materials (ASTM) 588 carbon steel; a weathering steel on which a surface layer of corrosion formed which protected the underlying material. The observed condition on the base plates was as expected and no loss of structural integrity occurred. The licensee believed that the contract suppression pool diver incorrectly identified the surface corrosion on the T-quencher base plates as a failed coating instead of the expected surface layer of corrosion characteristic of ASTM 588. Considering the worst-case scenario for potential blocking of emergency core cooling system (ECCS) suction strainers during design basis accidents, the total surface area of the T-quencher base plates was about 523 square feet. This represented an amount of material and area which was significantly less than the 1100 pounds of corrosion debris and 7,420 square feet of unqualified coatings that the licensee calculated to cause ECCS strainer blocking.

Observations of Heavy Load Movements

The inspectors observed a number of heavy load movements during Unit 1 refueling activities. These included the removal of the reactor vessel head on October 26, the removal of the steam separator on October 27, and the placement of the reactor vessel head on the reactor vessel on November 16, 1999. The operations occurred in a slow and controlled manner with adequate foreign material exclusion controls. The inspectors verified that the correct load paths were followed during the heavy load movements.

c. Conclusions

A number of human performance errors occurred during Unit 1 refueling outage activities. These errors were due, in large part, to the failure of licensee personnel to self-check or independently verify that the correct equipment was being operated, or was being removed for maintenance. The inspectors also concluded that although the closeout of the drywell was well-controlled, suppression pool closeout activities had not been rigorously controlled. The inspectors concluded that the conduct of heavy load movements observed during the refueling outage occurred in a slow and controlled manner and were performed well.

O1.3 Refueling Observations

a. Inspection Scope (60710)

The inspectors observed refueling activities during Unit 1 refueling outage L1R08 to determine whether pre-refueling activities specified in Technical Specifications (TSs) had been completed and whether refueling activities were controlled and conducted as required by TSs and approved procedures. Documents reviewed included the following:

- LaSalle Fuel Handling Procedure (LFP) 100-1, "Master Refuel Procedure," Revision 32
- LFP-100-6, "Verification of Fuel and Core Component Movements Within the Reactor and Spent Fuel Storage Pools," Revision 2
- Nuclear Design Information Transmittal NFM9900183, "Shutdown Margin Reactivity Calculation"
- LaSalle Fuel Handling Surveillance (LFS) 100-4, "Core Alterations and Control Blade Maintenance Move Shiftly Surveillances," Attachment A, Revision 16

b. Observations and Findings

The inspectors observed that continuous three-way communications were maintained between the refueling bridge and the control room core alterations NSO. All fuel assembly locations and orientations were verified by the senior reactor operator (SRO) in charge of fuel handling operations and a second verifier on the refueling bridge. Foreign material exclusion requirements were properly implemented. A calibrated area radiation monitor was present on the refueling bridge to monitor radiation levels and detect unexpected reactivity changes. The inspectors observed several turnovers between the SRO in charge of fuel handling operations, verifiers, and bridge operators during fuel handling operations. All were satisfactory, and adequately described operations in progress and equipment conditions.

In the control room, the core alterations NSO properly verified and reviewed source range monitor indications before and after each action that affected core reactivity. The NSO properly controlled core alterations by granting explicit permission to refueling bridge personnel to perform each fuel movement prescribed in the Nuclear Component Transfer List (NCTL). The inspectors reviewed the NCTL at both the refueling bridge and in the control room. In both locations, the list was properly maintained with relief turnover sheets present on the refueling bridge. The inspectors verified that shutdown margin reactivity requirements had been met for all core alteration operations planned during the second core alteration sequence. The inspectors also reviewed several completed core alteration shiftly surveillances. No deficiencies were identified.

Despite the overall positive observations by the inspectors during observed refueling activities, a number of human performance-related fuel handling errors occurred.

On September 24, 1999, during new fuel receipt activities, a new fuel assembly was oriented in the wrong direction. The NCTL required the assembly to be oriented in the southeast direction. During a fuel pool audit, it was discovered that the assembly was actually oriented in the southwest direction. The orientation of the fuel assembly in the fuel pool had no reactivity significance. The purpose of specifying the orientation was to have the fuel assembly in the final core load orientation to minimize the potential for mis-orienting it in the core. A prompt investigation identified the root cause as a human performance error due to a lack of attention-to-detail.

On November 1, 1999, following fuel sipping operations in the Unit 1 spent fuel pool, in the process of returning a fuel bundle to its original spent fuel pool location (L-47), refueling personnel identified that another bundle was already in that location, but an adjacent cell (K-47) was unexpectedly vacant. The refueling manager was notified and fuel sipping operations were immediately suspended. Refueling and engineering personnel confirmed that the fuel assembly in location L-47 was correct, and placed the grappled assembly in the K-47 position. A prompt investigation determined that the root cause of this event was multiple personnel errors which occurred during the fuel movement. In particular, three individuals fulfilling the fuel handler, second verifier, and supervisor roles failed to properly execute the verifications required to ensure that fuel movements occurred in the sequence prescribed by the NCTL and in accordance with LFP-100-6. Contributing factors that may have led to the event included use of the Unit 2 refueling bridge in the Unit 1 fuel pool, a thin crud layer on the index system, and elevated temperatures on the refuel floor. To address this event, the licensee re-enforced expectations regarding independent verification, performed a flush of the index system, and removed the second verifier from fuel movement responsibilities due to this and previous events at other sites.

On November 12, 1999, a fuel assembly was found to be oriented in the wrong direction. Step 691 of the NCTL required the assembly to be oriented in the northwest position. During performance of NCTL Step 701, fuel handling personnel identified that the assembly had been mis-oriented in the southeast position. A prompt investigation determined that due to a lack of attention-to-detail, the refueling bridge operator failed to position the fuel assembly in the proper orientation communicated to him. Also, the independent verifier and SRO in charge of fuel handling operations failed to properly execute a verification of the final fuel assembly position.

On November 14, 1999, during a Unit 1 final core verification audit, the licensee identified that the fuel assembly located in position 15-22 was oriented in the wrong direction. Per Step 200 of the NCTL, the assembly was to be in a southwest orientation. The core audit identified that the assembly was in the correct location but oriented in the northeast direction.

A prompt investigation determined that the root cause was human performance error due to a lack of attention-to-detail. Specifically, the refueling bridge operator failed to position the bundle in the proper direction per the NCTL. Also, the independent verifier and SRO in charge of fuel handling operations failed to properly execute a verification of the final fuel assembly position.

c. Conclusions

The inspectors concluded that adequate controls for the handling and storage of fuel during L1R08 were delineated in station procedures and in the vast majority of fuel movement activities were adequately conducted. However, due to a lack of attention-to-detail and a failure to adequately conduct self-checking and independent verifications, four fuel positioning errors occurred.

O1.4 Unit 2 Manual Reactor Scram Due to Electro-Hydraulic Control (EHC) System Failure

a. Inspection Scope (93702)

The inspectors reviewed the circumstances surrounding a Unit 2 manual reactor scram on November 16. The following procedures and surveillances associated with the scram and shutdown to Mode 3, "Hot Standby," were reviewed:

- LaSalle Operating Department Procedure (LGP) 3-2, "Reactor Scram," Revision 42
- LGP-2-1, "Normal Unit Shutdown," Revision 54
- LaSalle Instrument Surveillance (LIS) NR-408, "Unit 2 Source Range Monitor Alarms and Indications," completed November 16, 1999
- LIS-NR-401, "Unit 2 Source Range Monitor Rod Block Functional Test," completed November 16, 1999

b. Observations and Findings

On November 16, 1999, at 6:30 p.m., a Unit 2 turbine valve fast closure alarm and EHC malfunction alarm was received in the control room. Subsequently, intercept valves 4, 5, and 6 were observed closed and intercept valves 1, 2, and 3 were partially closed. The #1 main turbine control valve was observed oscillating and "A" low pressure turbine inlet pressure was erratic. Based on these indications, operators manually inserted a reactor scram. All control rods fully inserted, all systems responded as expected, and the Emergency Core Cooling Systems were not challenged.

The inspectors provided prompt onsite response to the event and verified that all equipment responded as required and the plant was placed in a stable condition as prescribed by LGP-3-2 and LGP-2-1. In addition, post-shutdown surveillances such as LIS-NR-408 and LIS-NR-401 were observed. During these reviews, the inspectors identified that LGP-3-2 required that at 30 minute intervals, maximum reactor vessel pressure and minimum metal temperature be recorded and verified to be to the right of curve B of TS Figure 3.4.6.1-1, "Minimum Reactor Vessel Metal Temperature vs. Reactor Vessel Pressure." The inspectors determined that although data was recorded at 30 minute intervals, it was not compared to TS Figure 3.4.6.1-1 as required. Since the data was far to the right of any operating limits, the error was considered minor, but demonstrated a lack of strict procedural compliance. This failure constitutes a violation of minor significance and is not subject to formal enforcement action.

The prompt investigation team was convened following the scram and determined that the cause of the event was an equipment failure in the EHC circuit. Specifically, the output of the intercept valve circuit amplifier card and its associated operational amplifier were found to have an offset voltage which would have resulted in a closure signal to the intercept valves. Also, the intercept valve amplifier card was found to be operating erratically and had insufficient output voltages for the corresponding input voltage values. The card failures caused a spurious fast closure of the Unit 2 combined intercept valves.

c. Conclusions

Operator actions to address a Unit 2 electro-hydraulic control system transient, which included action to manually scram the reactor, was good. All equipment responded as required and the plant was placed in a stable condition. One error regarding the verification of plant parameters against TS limits was observed.

O1.5 Unit 1 and Unit 2 Startup Observations

a. Inspection Scope (71711, 71707)

The inspectors observed plant startup, heatup, and approach to criticality for Unit 1 following completion of L1R08 and for Unit 2 following a manual scram due to an electro-hydraulic control system transient (Section O1.4). Documents reviewed included the following:

- LGP-1-1, "Normal Unit Startup," Revision 60
- LGP-1-S2, "Minimum Startup Checklist," Revision 35
- LaSalle Operating Procedure (LOP) RM-01, "Reactor Manual Control Operation," Revision 14
- LOA-RD-201, "Control Rod Drive Abnormal," Revision 1
- LOP-TG-02, "Turbine Generator Startup," Revision 40

b. Observations and Findings

On November 17-18, 1999, the inspectors observed portions of the Unit 2 startup and approach to criticality. On November 20-21, 1999, the inspectors observed portions of the Unit 1 startup and approach to criticality. Overall, the inspectors observed a cautious and methodical approach to criticality during both startups. In particular, the Qualified Nuclear Engineer (QNE) was observed to carefully monitor source range counts and reactor period. Reactor criticality was identified during both startups at an appropriate point. However, the inspectors identified the following deficiencies:

During the Unit 2 startup, the NSO manipulating control rods was observed to adjust feedwater flow to maintain water level within the pre-established operating band. The inspector discussed this potentially distracting activity with licensee management. The NSO was subsequently relieved of this collateral duty so that his full attention could be focused on his primary responsibility of core reactivity management.

During the Unit 2 startup, on two separate occasions, SRO intervention was required to ensure that equipment was operated to maintain plant parameters within required values. In one case, the reactivity SRO reminded the NSO manipulating control rods to reduce control rod drive pressure to within normal values for an initial attempt to withdraw a control rod. In a second case, the unit supervisor informed the "at the controls" NSO that he was at the uppermost limit of the allowable reactor vessel level band.

A feedwater heater 26 level alarm was observed to alarm frequently throughout the Unit 2 startup and approach to criticality. Actions to address this potentially distracting condition were slow, and eventually required that an operator continuously depress the alarm acknowledge pushbutton and monitor all other plant alarm indications to ensure that other alarming conditions would be identified.

Although QNE actions to monitor source range counts and reactor period for criticality for the Unit 2 startup was good, the NSO withdrawing control rods and the SRO providing oversight relied heavily on the QNE to perform those activities and did not conduct consistent independent monitoring of these indications. In addition, no independent verification of criticality was performed when criticality was declared by the QNE. Following discussion with licensee management, during the Unit 1 startup licensed operators provided good reactivity monitoring and verification of criticality.

During Unit 2 initial power ascension, Step E.11.28.2 of LGP-1-1 required the operators to verify that no average power range monitor (APRM) downscale lights were illuminated. The control room operators verified that no APRM downscale lights were illuminated on the front 2H13-P603 panel, but did not check the local APRM instrument drawers located on the back of the control panels. The inspectors checked the local instrument drawers and identified that six out of six APRM drawers indicated local downscale alarms. The inspectors brought the need to reset the local APRM drawers to the attention of a NSO who reset the local indications. The local APRM downscale alarms had been lit for approximately one hour before being reset by the NSO.

During the Unit 2 reactor startup on November 17, the inspectors identified an incorrect reference in Step E.10.1 of LGP-1-1. Step E.10.1 contained instructions for verifying source range monitor (SRM) to intermediate range monitor (IRM) overlaps during reactor startup and power ascension. The step incorrectly instructed the operators to compare IRM readings to previous calculations in Step E.5.2.3 which did not exist. Instead, Step E.10.1 should have referred the operators to Step E.7.2.4 which had previously calculated required IRM overlap readings. The inspectors informed the unit supervisor of the discrepancy.

During the subsequent Unit 1 reactor startup on November 20, the inspectors determined that although the unit supervisor was aware of the discrepancy, a procedure change request had not been processed to correct Step E.10.1 in the 3 days following the Unit 2 startup.

The inspectors observed that many of the discrepancies identified during the Unit 2 reactor startup were not repeated during the Unit 1 startup. Namely, the SRO and NSO responsible for bringing the Unit 1 reactor critical remained closely focused on reactivity management, SRM and IRM power levels, and reactor period. In addition, the SRO and

NSO observations of reactor parameters were independent of and concurrent with the QNE observations. Finally, control room distractions were minimized and operators took timely actions to maintain reactor water level within procedural bands.

c. Conclusions

Overall, the inspectors concluded that Unit 1 and Unit 2 restart activities were conducted in a well-controlled and deliberate manner. Although some minor deficiencies such as the assignment of responsibilities for controlling reactor vessel level and determining criticality were observed during the Unit 2 startup, licensee actions to address these concerns were effective as demonstrated by Unit 1 startup observations.

O1.6 Unit 1 and Unit 2 Exceed Licensed Thermal Power Limits

a. Inspection Scope (71707, 37551)

The inspectors reviewed the circumstances associated with LaSalle Unit 1 and Unit 2 exceeding the licensed thermal power limit of 3323 Megawatts thermal (Mwth). Documents reviewed included the following:

- "Prompt Investigation For LaSalle Unit 1 and Unit 2 Exceeding Licensed Thermal Power Limits," Revision 0
- PIF L1999-05978, "Process Computer Temperature Correction FW [Feedwater] and Unit 2 Millivolt Correction Factors," dated December 7, 1999
- Updated Final Safety Analysis Report (UFSAR) Section 4.4, "Thermal and Hydraulic Design," Revision 4
- UFSAR Section 6.3, Table 6.3-2, "Significant Input Variables Used in the Loss-of-Coolant-Accident Analyses," Revision 7
- UFSAR Section 15.6, Table 15.6-9, "Loss-of-Coolant-Accident Parameters To Be Tabulated for Postulated Accident Analyses," Revision 0

b. Observations and Findings

On December 7, 1999, licensee personnel identified that the computer program designed to apply a correction factor to account for the differences between design feedwater temperature and actual feedwater temperature had been disabled on Unit 1 and Unit 2. The impact was a higher feedwater flow than indicated and correspondingly, a higher core thermal power than indicated.

In addition, the licensee identified a second potential error involving an unverified correction factor applied to Unit 2 feedwater flow used in the thermal power calculation. The correction involved a millivolt signal provided to the process computer to account for differences from the feedwater flow sensor readings in the field to the process computer.

Initial licensee investigation suggested that the licensed thermal power limits of 3323 Mwth were not exceeded by more than 0.14 percent (4.65 Mwth) for Unit 1 and 0.21 percent (6.98 Mwth) for Unit 2 . The immediate corrective action taken by the station on December 7 was to administratively limit power output of each unit to a maximum value of 99.5 percent (3306 Mwth) until a prompt investigation had been completed and corrections to the process computer thermal power calculations had been approved and implemented. The Unit 2 feedwater flow millivolt correction factor was subsequently removed from Unit 2 on December 8, after it was determined that the factor was redundant to other uncertainties included in the assumptions of the thermal power calculation. The program used to apply the correction factor for the difference between design and actual feedwater temperature was subsequently enabled on December 9, and both units returned to full power operation.

Following identification of the issue, the licensee initiated a root cause investigation to determine and examine the extent of the condition associated with exceeding licensed thermal power, software program configuration control, and the potential for having exceeded any licensed thermal safety limits. This is an Unresolved Item (URI) (50-373/99022-01; 50-374/99022-01) pending a review of the root cause investigation report.

c. Conclusions

An error in the thermal power computer calculation used for Unit 1 and Unit 2 allowed Unit 1 to exceed the licensed thermal power limit (3323 megawatts thermal) by up to 0.14 percent and Unit 2 by up to 0.21 percent. The error was attributed to a failure to appropriately address correction factors in the feedwater flow calculations.

O1.7 Cold Weather Preparations Review

a. Inspection Scope (71714)

The inspectors conducted a review of winter operation preparations and performed walkdowns of the station heating system, cycled condensate storage tanks (CSTs), fire protection headers, and the turbine building, reactor building, primary containment, and control room ventilation systems to determine whether the licensee had effectively implemented a program to protect safety-related systems against extremely cold weather. Documents reviewed included the following:

- LOS-ZZ-A2, "Preparations for Winter/Summer Operation," Revision 18
- Work Request (WR) 990082143, "Unit 2 CY [Cycled Condensate Storage] Tank Heater CR3 Relay"
- WR 990106857, "Unit 1 CY Tank Heater Control Power Logic"
- LaSalle Operating Annunciator Response Procedure (LOR) 1PM10J-A507, "Cycled Condensate Storage Tank 1CY01T Temperature High/Low," Revision 0
- LOR-2PM10J-A507, "Cycled Condensate Storage Tank 2CY01T Temperature High/Low," Revision 0
- General Electric Design Specification Data Sheet 238X173AAG1, "Reactor Core Isolation Cooling System," Revision 15
- LaSalle Instrument Maintenance Procedure (LIP) GM-907, "Calibration of Temperature Indicating or Switching Devices," Revision 2.

b. Observations and Findings

All systems were found to be ready for winter operations with the exception of the cycled condensate storage tanks which had malfunctioning electrical immersion heaters. The inspectors reviewed two outstanding work orders associated with the CST immersion heaters and determined that they were scheduled for repair during December 1999. The same immersion heaters were not available during the last winter season, but due to the makeup and rejecting flow characteristics of the condensate cycle, the outside temperature of the CSTs never fell below 40 degrees fahrenheit (°F).

The inspectors identified that LOS-ZZ-A2 contained provisions for verifying cold weather protection for the meteorological tower instrument building. The meteorological tower was required by TS 3.3.7.3 to be operable at all times. During October 1999, however, the meteorological tower was replaced. The inspectors identified that LOS-ZZ-A2 did not contain any provisions for verifying cold weather protection for the new meteorological tower. The inspectors discussed the observation with emergency planning personnel and determined that the load dispatch organization monitored remote temperature alarms associated with the new meteorological tower and would respond to any abnormalities. In addition, the new meteorological tower contained a standby propane generator which was independent of offsite power and capable of supporting the new meteorological buildings heating needs during cold weather periods. A procedure change request was subsequently submitted to eliminate reference to the old meteorological tower from LOS-ZZ-A2.

c. Conclusions

The inspectors concluded that licensee preparations for cold weather were adequate.

O8 Miscellaneous Operations Issues

O8.1 (Closed) Licensee Event Report (LER) 50-373/99004-00: Average Power Range Monitors (APRMs) Inoperable During Refueling Due to Improper Isolation of Local Power Range Detectors.

On November 1, 1999, with Unit 1 in Mode 5, the licensee declared all APRMs inoperable due to a degraded condition with the APRM flow-biased setdown scram function. Six LPRM string power supply fuses had been removed without the respective LPRMs (24 total) being bypassed. As a result, LPRM inputs were transmitted to APRM averaging circuitry resulting in a lower than actual indicated power level.

The licensee conducted a prompt investigation and determined the root cause as a lack of knowledge by instrument maintenance department and operations personnel. Although operations personnel were aware that the LPRMs were inoperable with the fuses removed, the impact on the APRMs was not recognized. As part of the licensee's immediate corrective actions, the input from the affected LPRMs were bypassed in the APRM power integration circuitry. The significance of the event was low since the IRM system was operable and provided a high neutron flux scram at a lower flux than the APRM neutron flux setdown scram.

Technical Specification 3.3.6, Table 3.3.6-1, Action 61, required that in Mode 5 with two or more APRM Neutron Flux High channels inoperable, place at least one inoperable channel in the tripped condition within 1 hour. The failure to bypass LPRMs when fuses were removed caused incorrect inputs to the APRM's rendering them inoperable. With the APRM's inoperable, failure to take the actions required by TS 3.3.6 was a violation (50-373/99022-02; 50-374/99022-02). However, this Severity Level IV violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy. This item was entered into the licensee's corrective action program as PIF L1999-05279.

O8.2 <u>(Closed) LER 50-374/99003-00</u>: Unit 2 Manual Reactor Scram Due to Electro-Hydraulic Control (EHC) System Failure.

This event is discussed in Section O1.4 of this report. No new issues were revealed in this LER.

O8.3 <u>(Closed) Inspection Followup Item (IFI) 50-373/97303-01</u>: Conflict Between LGAs [LaSalle General Abnormal Procedures] and TS 3.10.8.

This item was entered into the licensee's corrective action program as Action Tracking Matrix (ATM) item 20801. This item is closed.

O8.4 <u>(Closed) IFI 50-373/97303-02</u>: Exam Security Procedure Weakness.

This item was entered into the licensee's corrective action program as ATM 20801. This item is closed.

O8.5 <u>Review of Annual Institute for Nuclear Power Operations (INPO) Report</u>

The inspectors reviewed the annual INPO assessment report for the annual INPO inspection conducted from January 25 through February 4, 1999. No safety or training issues not previously identified by NRC inspections were contained in the report.

<u>II. Maintenance</u>

M1 Conduct of Maintenance

M1.1 <u>Surveillance Observations</u>

a. <u>Inspection Scope (61726, 62707, 92902)</u>

The inspectors observed all or portions of the following surveillance test activities. Included in the inspection was a review of the surveillance test procedures listed, as well as the appropriate Updated Final Safety Analysis Report (UFSAR) sections regarding the activities. The inspectors verified that the surveillance tests for the activities observed met TS requirements.

- LaSalle Technical Surveillance (LTS) 500-111, "Integrated Division III Response Time Surveillance," Revision 7
- LTS-800-102, "1A Diesel generator, 1DG01K, Start and Load Acceptance Surveillance," Revision 4
- LTS-500-109, "Integrated Division 1 Response Time Surveillance," Revision 10
- LOP-NB-01, "Reactor Vessel Leakage Test," Revision 33
- LOS-RH-R1, "LPCI [Low Pressure Coolant Injection] Injection Line Check Valve Inservice Test, Attachment 1C," Revision 10
- LOS-RI-Q3, "Reactor Core Isolation Cooling (RCIC) System Pump Operability and Valve Inservice Tests In Conditions 1,2, and 3, Attachment 1A," Revision 30
- LOS-RI-Q5, "RCIC System Pump Operability, Valve Inservice Tests in Conditions 1, 2, 3 and Cold Quick Start, Attachment 2A," Revision 11
- LOS-RI-Q5, "RCIC System Pump Operability, Valve Inservice Tests in Conditions 1, 2, 3 and Cold Quick Start, Attachment 1A," Revision 12
- LOS-SC-Q1, "SBLC [Standby Liquid Control] Pump and Motor-Operated Valve Operability/Inservice Test and Explosive Valve Continuity Check," Revision 14

b. <u>Observations and Findings</u>

The inspectors observed response time testing of the 1B emergency diesel generator (DG) in accordance with surveillance test LTS-500-111. The test simulated a loss of offsite power concurrent with an ECCS actuation test signal. The surveillance test verified that the emergency bus de-energized, the 1B DG auto-started and energized the emergency bus within 13 seconds, and the DG operated for greater than or equal to 5 minutes at rated voltage and frequency.

The inspectors reviewed the completed surveillance and independently verified that strip chart data had been satisfactorily translated into measured parameters for comparison against acceptance criteria. The data was accurately translated and met acceptance limits. However, the inspectors identified that although the last three steps of the procedure were completed, entries were not made in the surveillance to identify their completion. In addition, the inspectors identified that the diesel generator strip chart data for voltage was mis-labeled. Although the safety significance of these errors was minimal, it demonstrated a lack of attention-to-detail by the individuals who performed and reviewed the test. The licensee initiated PIF L1999-05626 to identify this issue for entry into the corrective action program.

The inspectors observed starting and load acceptance testing of the 1A DG in accordance with LTS-800-102. The surveillance used a simulated ECCS actuation signal to fast-start the DG. All start times, voltage, and frequency parameters fell within expected values. No deficiencies were identified.

The inspectors observed portions of the reactor pressure vessel inservice leakage test in accordance with LOP-NB-01. Pressure was increased in a slow and controlled manner to the final hydrostatic pressure of 1030 pounds per square inch gauge (psig). The inspectors verified that plant conditions supported the hydrostatic test and that reactor pressure vessel metal temperatures and system pressures met brittle fracture prevention limits. Once at hydrostatic pressure, inspections both inside and outside primary containment revealed minor system leakage at valve packing, flanges, and instrument racks. The identified leakage was repaired prior to Unit 1 restart. No deficiencies were identified.

The inspectors observed Unit 1 "C" LPCI injection line check valve inservice testing in accordance with LOS-RH-R1. The surveillance test took water from the suppression pool and injected it into the reactor vessel in order to cycle the "C" LPCI injection line check valve. The "C" LPCI pump functioned as expected and obtained an injection flow rate sufficient to verify that the injection check valve had cycled to the full open position. No deficiencies were identified.

The inspectors observed response time testing of the Unit 0 DG in accordance with surveillance test LTS-500-109. The test simulated a loss of offsite power concurrent with an ECCS actuation test signal. The surveillance test verified that the emergency bus de-energized, the Unit 0 DG auto-started and energized the emergency bus with its loads within 13 seconds, and the DG operated for greater than or equal to 5 minutes at rated voltage and frequency. No deficiencies were identified.

The inspectors observed performance of LOS-RI-Q3, Attachment 1A, from the control room and the local pump room during initial Unit 1 power ascension activities. The surveillance was required to verify that the RCIC pump could provide rated flow to the reactor vessel at normal reactor steam pressures. During the surveillance, operators identified flow and suction and discharge pressure oscillations caused by RCIC turbine governor transients. The unit supervisor ordered the surveillance stopped and governor adjustments to proceed using the instrument maintenance governor calibration and RCIC pump manual operation procedures. The governor adjustments required several starts and shutdowns of the RCIC turbine. During the adjustments, the inspectors observed close communications between the system engineer and instrument mechanics in the local pump room and control room personnel. The inspectors reviewed the completed surveillance and verified that all RCIC pump parameters met the required acceptance criteria and supported continued power ascension. No deficiencies were identified.

The inspectors observed a cold quick-start test of the Unit 2 RCIC pump in accordance with LOS-RI-Q5, Attachment 2A. During the surveillance, difficulty was experienced in meeting the pump discharge flow and pressure requirements of TS 4.7.3.b. The surveillance verified that the RCIC pump developed a flow of greater than or equal to 600 gallons per minute (gpm) when steam was supplied to the turbine at 1000 psig. Step 7.0 of LOS-RI-Q5 contained additional and more restrictive criteria that RCIC pump discharge flow be 600 gpm (+5, -0) with RCIC pump discharge pressure at least 85 psig greater than reactor pressure.

Unable to achieve the exact flow and pressure requirements of Step 7.0, engineering personnel determined that the 600 gpm (+5, -0) requirement from inservice testing data recorded in Step 8.1.2 had been inappropriately applied to the TS verification performed in Step 7.0. A prompt operability determination was performed which documented that the RCIC pump was operable. No deficiencies were identified.

The inspectors observed the performance of LOS-RI-Q5, "RCIC System Pump Operability, Valve Inservice Tests in Conditions 1, 2, 3 and Cold Quick Start," Attachment 1A, Revision 12, on December 7, 1999. The surveillance was observed from both the control room and the local pump room locations.

During the surveillance, the inspectors identified that although Step 6.10 required that suppression pool average temperature be verified to be less than or equal to 105°F at least once per 5 minutes and documented on LOS-AA-S101, Attachment G, after the system was started, this was not accomplished until 15 minutes after the system was started. The inspectors reviewed the pre-job briefing package for this surveillance and identified that not performing the suppression pool temperature log readings had been identified as an error likely situation. Shift supervision also failed to identify this concern. The safety significance of this error was minor since suppression pool temperature was well below the 105°F limit throughout the surveillance. Therefore, this failure constituted a violation of minor significance and will not be subject to enforcement action. However, it demonstrated a lack of attention-to-detail on the part of the crew performing the surveillance.

The inspectors requested a copy of the completed surveillance following management review and approval. During the review of that surveillance, the inspectors identified that Step 4.2 which verified the opening capability of the RCIC water leg pump check valve, had not been documented as completed. The inspectors brought this to the attention of licensee management who subsequently determined that although the verification was performed, due to a lack of attention-to-detail, it was not properly documented and was not identified during management review. The licensee generated PIF L1999-06043 to enter this issue into the corrective action program.

Locally, the inspectors verified that all pump and turbine vibration and speed readings were at or near reference levels and that all measuring equipment had current calibrations. The inspectors observed and verified proper operation of all components associated with the RCIC pump barometric condenser. Operators correctly adjusted inboard and outboard gland steam leakoff pressures when those parameters fell outside of recommended ranges. Satisfactory operation of the RCIC trip and throttle valve and overspeed trip mechanism was also observed.

The inspectors observed the performance of LOS-SC-Q1 on Unit 1 on December 8, 1999. During the surveillance, the inspectors observed that while establishing pressure to the desired value, the discharge gauge indication needle swung about 220 psig in range and that the operators referenced the farthest swing to the right as the actual pressure. The inspectors questioned the operators since it seemed that the mid-range indication would be appropriate. Subsequently, the operator confirmed through the field supervisor that the mid-range reading was the actual value and adjusted the discharge pressure accordingly. The inspectors discussed this issue with training personnel who determined that no formal training on this matter existed in the non-licensed operator training program. The licensee generated PIF L1999-06044 to enter this issue into their corrective action program.

c. <u>Conclusions</u>

The inspectors concluded that overall, observed surveillances were performed satisfactorily and met TS requirements. Although some procedure deficiencies and documentation errors were identified, these errors were minor in nature and did not impact the surveillance activities or results.

M8 Miscellaneous Maintenance Issues

M8.1 (Closed) IFI 50-373/98002-01; 50-374/98002-01: Periodic Evaluations of Equipment Monitored Under the Maintenance Rule.

The quality and effectiveness of the Maintenance Rule (10 CFR 50.65) periodic evaluation could not be fully evaluated because both units had been shutdown during most of the assessment period. Similarly, the quality and effectiveness of balancing reliability and availability could not be fully evaluated because both units had been shutdown during most of the assessment period. Both of these areas will be inspected periodically under the Maintenance Rule Implementation inspectable area of the Risk-Informed Baseline Inspection Program. As such, there is no longer a need to track this item.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Review of Modification Activities

a. Inspection Scope (37551)

The inspectors reviewed Unit 1 Design Change Package 9600289, "Restoration of Jet Pump No. 9," associated with L1R08. The inspectors observed portions of Jet Pump 9 and 10 replacement activities in the reactor vessel, verified adequate nondestructive testing methods, and reviewed design change information material. Jet Pump 10 was replaced along with Pump 9 since both pumps were on the same recirculation riser in the reactor vessel annulus. Replacing only one pump could create a flow imbalance resulting in excessive vibration and potential cracking of the riser brace welds.

b. Observations and Findings

Replacement activities in the reactor vessel were performed in a controlled and deliberate manner with adequate foreign material controls and communication practices. Remote visual inspection methods were employed to determine the dimensions of replacement wedges used to ensure the structural rigidity of the new jet pumps. The inspectors verified that the visual inspection techniques appropriately scaled dimensions from the old jet pumps and provided accurate measurements for machining of the wedges for the new jet pumps. The inspectors ensured that the modified jet pump assembly maintained two-thirds core height flooding capabilities as required in the accident analyses for a loss-of-coolant-accident. Design change information was adequately prepared and addressed the safety-related issues associated with the jet pump modification.

c. <u>Conclusions</u>

Jet pump modification activities were performed in a satisfactory manner. Engineering reviews addressed the appropriate recirculation system safety functions. Remote visual inspection techniques properly measured riser-to-jet pump gap dimensions.

E2.2 <u>Review of "A" Residual Heat Removal (RHR) Service Water Pump Surveillance Activities</u>

a. <u>Inspection Scope</u>

The inspectors reviewed the circumstances surrounding the failure of the 2A RHR service water pump to meet inservice testing requirements during a quarterly surveillance test. Documents reviewed included the following:

- PIF L1999-05883, "'A' RHR WS [Service Water] Pump Falls Into the Required Action Range on D/P [Differential Pressure]," dated November 30, 1999
- PIF L1999-05891, "Pump Failed IST [Inservce Testing] Criteria During LOS-RH-Q1, Attachment 2D," dated November 30, 1999
- WR 99009337401, "LOS-RH-Q1, 2A RHR WS Operability and Inservice Test," dated November 29, 1999
- WR 990012109001, "LOS-RH-Q1, 2A RHR WS Operability and Inservice Test," dated November 30, 1999
- 2A RHR Service Water Pump Differential Pressure Inservice Testing (IST) Records, July 18, 1995 to September 7, 1999.

b. <u>Observations and Findings</u>

The inspectors reviewed the failure of the 2A RHR service water pump to meet differential pressure requirements during performance of quarterly surveillance LOS-RH-Q1. The acceptable range for pump differential pressure was 61.2 to 74.8 pounds per square inch differential (psid). The calculated value for 2A service water pump differential pressure found during the performance of LOS-RH-Q1 was 60.5 psid. This placed the 2A RHR service water pump in the IST required action range. The licensee documented the failure in PIFs L1999-05883 and L1999-05891 and re-calibrated the 2A RHR service water pump suction and discharge pressure gauges as well as the flow measuring instrument. All were found to be within tolerance. As part of the troubleshooting process, the flow transmitter instrument sensing lines were then backfilled. The surveillance was re-performed and the 2A RHR service water pump was verified to be within IST tolerances with a differential pressure of 64.7 psid. The apparent cause of the initial surveillance failure was the incomplete filling of the flow transmitter sensing lines.

During a review of 2A RHR service water pump IST history, the licensee identified that the pump had routinely run with a differential pressure of about 68 psid for the 5 years preceding 1998. The service water pump was rebuilt during a Unit 2 refueling outage and re-baselined in February 1999 with a differential pressure of 68 psid. When the surveillance was performed in March 1999, however, the differential pressure experienced a step drop to 62 psid. The surveillance was performed again in September 1999 and the differential pressure remained at the lower value of 62 psid. Inservice testing data is trended by the IST coordinator and the system engineer in order to determine the health of the equipment and to make repairs or adjustments before equipment parameters enter the required action range. In this case, the step change in 2A RHR service water pump differential pressure performance that occurred in March and September 1999 was not identified. Had the step change been identified by engineering personnel, it would have provided an early indication that something had changed with the pump or its associated monitoring equipment. The licensee generated PIF L1999-05883 to enter this issue in the corrective action program.

c. Conclusions

During quarterly surveillance testing of the 2A RHR service water pump, the licensee determined that pump differential pressure was within the inservice testing required action range. Subsequent investigation revealed a weakness in the equipment trending process when it was discovered that engineering personnel had failed to identify a previous step change in pump differential pressure performance.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 Unit 1 Reactor Water Cleanup Valve Aisle Elevated Dose Rate

a. Inspection Scope (71750)

The inspectors reviewed the circumstances surrounding the identification of unexpected elevated dose rates in the Unit 1 reactor water cleanup valve aisle by licensee personnel.

b. Observations and Findings

On December 6, 1999, a field supervisor entered the Unit 1 reactor water cleanup valve aisle to walkdown the system to identify any abnormal conditions prior to performing a planned system flush, fill, and vent. The area was controlled as a high radiation area for dose rates less than 1000 millirem per hour (mrem/hr). Upon entering the room, the field supervisor received an electronic dosimeter dose rate alarm. The field supervisor immediately exited the area and contacted radiation protection personnel. The dose rate alarm was set at 300 mrem/hr. The highest dose rate recorded by the electronic dosimeter was 440 mrem/hr and the total accumulated dose was 1.9 mrem.

A subsequent radiation protection survey identified a local radiation field reading 2.2 roentgen-equivalent-man per hour (Rem/hr) at 30 centimeters. When previously surveyed, this local radiation field was reading about 800 mrem/hr at 1 foot. The followup survey indicated that the dose rate recorded by the supervisor's electronic dosimeter was consistent with radiation levels in the room.

The licensee determined that the apparent cause of the event was a weakness in the radiation protection surveillance program. This weakness allowed access to the area without an evaluation of radiological changes since periodic surveys were only time-based, and did not factor in the performance of operational evolutions.

As part of the licensee's immediate corrective actions, the room was surveyed and posted as a high radiation area with dose rates greater than 1 Rem/hr; and the Unit 1 and Unit 2 reactor water cleanup pump room doors were locked to isolate the area to meet TS requirements. In addition, the licensee planned to re-evaluate the practice of allowing operations personnel to enter high radiation areas without prior radiation protection briefings, review the control of areas that have the potential for transient dose rates, and revise plant area survey frequency requirements to more effectively link survey requirements to work evolutions that have the potential to alter radiological conditions.

Technical Specification 6.1.1.4 requires, in part, that areas accessible to personnel with radiation levels such that a major portion of the body could receive a dose greater than 1000 millirem in 1 hour shall be locked except during periods when access to the area is required with positive controls over each individual entry. The failure to control the Unit 1 reactor water cleanup valve aisle as a locked high radiation area was an example where the requirements of TS 6.1.1.4 were not met and was a violation (50-373/99022-03; 50-374/98022-03). However, this Severity Level IV violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1.a of the NRC Enforcement Policy. This item was entered into the licensee's corrective action program as PIF L1999-05963.

c. Conclusions

The inspectors concluded that the licensee failed to control a high radiation area with area dose rates exceeding 1000 mrem/hr in accordance with TS requirements.

P8 Miscellaneous Security and Safeguards Issues

P8.1 (Closed) IFI 50-373/99010-01; 50-374/99010-01: Security Lighting Deficiencies.

This item was entered into the licensee's corrective action program as ATM 3885. This item is closed.

F1 Control of Fire Protection Activities

F1.1 Review of Fire Watch Activities During the Unit 1 Refueling Outage and Unit 1 Startup

a. Inspection Scope (71750)

Fire protection headers were isolated to a large part of the Unit 1 reactor building during the Unit 1 refueling outage. The inspectors reviewed the licensee's compensatory actions and selected fire watch activities during the time period when the fire protection header was isolated. The inspectors also reviewed the licensee's response to a lubricating oil leak on the 1A turbine-driven reactor feedwater pump (TDRFP). During tours of the Unit 1 turbine building, auxiliary building, reactor building, and drywell during the refueling outage, the inspectors verified adequate controls of transient combustibles. Documents reviewed during the inspection included:

- LaSalle Administrative Procedure (LAP) 900-40, "Fire Watch Guidelines," Revision 7
- LaSalle County Station Post Order (LPO) 127, "Fire Impairment & Daily Fire Door Inspections, Revision 0
- Hourly Fire Watch Inspection Log, LPO 127, Security Department, November 1 and 2, 1999
- Hourly Fire Watch Inspection Log, LAP-900-40, Construction Department, October 29 and 30, 1999
- PIF L1999-05907, "Failure to Notify Fire Marshall About 1A TDRFP Oil Leak," dated November 30, 1999

b. Observations and Findings

During a tour of the Unit 1 cable spreading room, the inspectors identified that the licensee had identified a pinhole leak in a sprinkler line providing fire protection for a cable tray. The inspectors discussed the significance of the leak as a potential consequence of microbiologically influenced corrosion occurring in the carbon steel fire protection system with the station Fire Marshall. The Fire Marshall stated that one similar leak had been identified in the last 2 years, the site was involved in industry initiatives to monitor and mitigate fire protection system degradation, and that all portions of the fire protection system had been able to satisfy test flow requirements during surveillance tests. The pinhole leak in the cable spreading room fire protection line was subsequently repaired.

With large portions of the fire protection system isolated in the Unit 1 reactor building during the refueling outage, the inspectors reviewed the activities of fire watch personnel. Construction department personnel were assigned Unit 1 hourly fire watch duties for elevations in the reactor building below the 710' level. Security personnel were assigned fire watch duties for elevations at and above the 710' level. Hourly construction and security department fire watch logs documented that all inspections had been performed satisfactorily in accordance with the requirements of LAP-900-40 and LPO-127.

During routine operator rounds on November 30, 1999, Unit 1 operators noticed an oil leak from the 1A TDRFP low pressure bearing outboard oil seal. When discovered, about seven gallons of lubricating oil had leaked from the bearing and collected on the floor of the 731' elevation of the heater bay below the TDRFP. The oil was contained and a collection device for further leakage was placed around the leaking bearing. The Unit 1 field supervisor walked down the TDRFP systems and the heater bay area below the pump to ensure that no fire hazards existed. None were found. The field supervisor was the qualified fire chief for the shift.

The inspectors performed an independent walkdown of the leaking area on December 1. Although the inspectors identified that slight adjustments were needed to the bearing oil collection device to ensure all leaking oil was being contained, no fire hazards were found. The inspectors discussed the issue with the station Fire Marshall to verify his understanding of any potential fire hazards. The Fire Marshall stated that he was unaware of the oil leak and had not performed any independent walkdowns to determine the potential hazards that existed. The inspectors subsequently determined that although the operating crew had responded appropriately to the oil leak about 25 hours earlier, the station Fire Marshall had not been informed of the issue. In addition, the Fire Marshall had not maintained an awareness of plant operational issues through attendance at preshift briefings, plan-of-the-day meetings, or a review of crew operating logs available on the site computer system concerning the potential fire hazard.

c. Conclusions

Compensatory fire watches during the Unit 1 refueling outage were performed in a satisfactory manner. During a walkdown of potential fire hazards, the inspectors identified a lack of station Fire Marshall involvement in a 1A TDRFP lubricating oil leak.

F8 Miscellaneous Fire Protection Issues

F8.1 (Closed) IFI 50-373/98015-01: Fire Protection Ionization Detector Design Basis.

This item was entered into the licensee's corrective action program as ATM 772. This item is closed.

F8.2 (Closed) IFI 50-373/98015-03: Fire Protection Deluge Valve Testing.

This item was entered into the licensee's corrective action program as ATM 773. This item is closed.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the results of the inspection to licensee management at an exit meeting on December 20, 1999. The licensee acknowledged the findings presented. The inspectors asked the licensee if any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

<u>ComEd</u>

J. Benjamin, Site Vice President
J. Meister, Station Manager
D. Bost, Site Engineering Manager
W. Riffer, Nuclear Oversight Manager
R. Gilbert, Operations Manager
F. Spangenberg, Regulatory Assurance Manager
J. Pollock, System Engineering Manager
F. Gogliotti, Design Engineering Supervisor
S. Taylor, Radiation Protection Manager

INSPECTION PROCEDURES USED

IP 37551	Onsite Engineering
IP 60710	Refueling Activities
IP 61726	Surveillance Observation
IP 62707	Maintenance Observation
IP 71707	Plant Operations
IP 71711	Plant Startup From Refueling
IP 71714	Cold Weather Preparations
IP 71750	Plant Support Activities
IP 92700	Onsite Follow-up of Written Reports of Nonroutine Events
IP 92901	Followup - Plant Operations
IP 92902	Followup - Maintenance
IP 92903	Followup - Engineering
IP 93702	Prompt Onsite Response to Events at Operating Power Reactors

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-373/99022-01;50-374/99022-01	URI	Units Exceed Licensed Thermal Power Limits
50-373/99022-02;50-374/99022-02	NCV	Failure to Bypass LPRMs
50-373/99022-03;50-374/99022-03	NCV	Improperly Controlled High Radiation Area

Closed

50-373/99022-02;50-374/99022-02	NCV	Failure to Bypass LPRMs
50-373/99022-03;50-374/99022-03	NCV	Improperly Controlled High Radiation Area
50-373/99004-00	LER	Improper Isolation of LPRMs
50-374/99003-00	LER	Unit 2 Scram Due to EHC Failure
50-373/97303-01	IFI	Conflict Between LGAs and TS 3.10.8
50-373/97303-02	IFI	Exam Security Procedure Weaknesses
50-373/98002-01;50-374/98002-01	IFI	Evaluation of Maintenance Rule Equipment
50-373/99010-01;50-374/99010-01	IFI	Security Lighting Deficiencies
50-373/98015-01	IFI	Ionization Detector Design Basis
50-373/98015-03	IFI	Fire Protection Deluge Valve Testing

Discussed

None

LIST OF ACRONYMS USED

APRM	Average Power Range Monitor
ASTM	American Society of Testing and Materials
ATM	Action Tracking Matrix
CRD	Control Rod Drive
CST	Condensate Storage Tank
DG	Diesel Generator
DRP	Division of Reactor Projects
ECCS	Emergency Core Cooling System
EHC	Electro-Hydraulic Control
°F	Degrees Fahrenheit
gpm	Gallons Per Minute
IFI	Inspection Followup Item
INPO	Institute for Nuclear Power Operations
IP	Inspection Procedure
IRM	Intermediate Range Monitor
IST	Inservice Testing
LAP	LaSalle Administrative Procedure
LER	Licensee Event Report
LFP	LaSalle Fuel Handling Procedure
LFS	LaSalle Fuel Handling Surveillance
LGA	LaSalle General Abnormal Procedure
LGP	LaSalle Operating Department Procedure
LIP	LaSalle Instrument Maintenance Procedure
LIS	LaSalle Instrument Surveillance
LOA	LaSalle Abnormal Operating Procedure
LOP	LaSalle Operating Procedure
LOR	LaSalle Operating Annunciator Response Procedure
LOS	LaSalle Operating Surveillance
LPCI	Low Pressure Coolant Injection
LPO	LaSalle County Station Post Order
LPRM	Local Power Range Monitor
LTS	LaSalle Technical Surveillance
Mwth	Megawatts Thermal Power
NCTL	Nuclear Component Transfer List
NSO	Nuclear Station Operator
PIF	Problem Identification Form
psid	Pounds Per Square Inch Differential
psig	Pounds Per Square Inch Gauge
QNE	Qualified Nuclear Engineer
RCIC	Reactor Core Isolation Cooling
REM	Roentgen Equivalent Man
RHR	Residual Heat Removal
SBLC	Standby Liquid Control
SRM	Source Range Monitor
SRO	Senior Reactor Operator
TDRFP	Turbine-Driven Reactor Feedwater Pump
TS	Technical Specification

UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
WR	Work Request