July 24, 2000

Mr. Oliver D. Kingsley
President, Nuclear Generation Group
Commonwealth Edison Company
ATTN: Regulatory Services
Executive Towers West III
1400 Opus Place, Suite 500
Downers Grove, IL 60515

SUBJECT: LASALLE COUNTY STATION - INSPECTION REPORT 50-373/2000006(DRP); 50-374/2000006(DRP)

Dear Mr. Kingsley:

On June 30, 2000, the NRC completed an inspection at your LaSalle County Station. The enclosed report presents the results of that inspection. The results of this inspection were discussed on June 30, 2000, with Mr. C. Pardee and other members of your staff.

This inspection was an examination by resident and regional inspectors of activities conducted under your license as they relate to reactor safety, verification of performance indicators, event followup, and to compliance with the Commissions rules and regulations and with the conditions of your license. Within these areas, the inspection consisted of a selective examination of procedures and representative records, observations of activities, and interviews with personnel.

Based on the results of this inspection no findings were identified.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available **electronically** for public inspection in the NRC Public Document

Room **or** from the *Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from* the NRC Web site at http://www.nrc.gov/NRC/ADAMS/index.html (the Public Electronic Reading Room).

Sincerely,

Original signed by
Melvyn N. Leach, Chief
Melvyn N. Leach, Chief
Reactor Projects Branch 2

Docket Nos. 50-373; 50-374
License Nos. NPF-11; NPF-18

Enclosure: Inspection Report 50-373/2000006(DRP);
50-374/2000006(DRP)

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REGION III

Docket Nos:	50-373, 50-374
License Nos:	NPF-11, NPF-18
Report Nos:	50-373/2000006(DRP); 50-374/2000006(DRP)
Licensee:	Commonwealth Edison Company
Facility:	LaSalle County Station, Units 1 and 2
Location:	2601 N. 21st Road Marseilles, IL 61341
Dates:	May 6 - June 30, 2000
Inspectors:	E. Duncan, Senior Resident Inspector P. Krohn, Resident Inspector R. Jickling, Emergency Preparedness Specialist Inspector K. Riemer, Project Engineer W. Scott, Reactor Engineer
Approved by:	Melvyn N. Leach, Chief Reactor Projects Branch 2 Division of Reactor Projects

NRC's REVISED REACTOR OVERSIGHT PROCESS

The federal Nuclear Regulatory Commission (NRC) recently revamped its inspection, assessment, and enforcement programs for commercial nuclear power plants. The new process takes into account improvements in the performance of the nuclear industry over the past 25 years and improved approaches of inspecting and assessing safety performance at NRC licensed plants.

The new process monitors licensee performance in three broad areas (called strategic performance areas): reactor safety (avoiding accidents and reducing the consequences of accidents if they occur), radiation safety (protecting plant employees and the public during routine operations), and safeguards (protecting the plant against sabotage or other security threats). The process focuses on licensee performance within each of seven cornerstones of safety in the three areas:

Reactor Safety

- Initiating Events
- Mitigating Systems
- Barrier Integrity
- Emergency Preparedness

Radiation Safety

- Occupational
- Public

Safeguards

- Physical Protection

To monitor these seven cornerstones of safety, the NRC uses two processes that generate information about the safety significance of plant operations: inspections and performance indicators. Inspection findings will be evaluated according to their potential significance for safety, using the Significance Determination Process, and assigned colors of GREEN, WHITE, YELLOW or RED. GREEN findings are indicative of issues that, while they may not be desirable, represent very low safety significance. WHITE findings indicate issues that are of low to moderate safety significance. YELLOW findings are issues that are of substantial safety significance. RED findings represent issues that are of high safety significance with a significant reduction in safety margin.

Performance indicator data will be compared to established criteria for measuring licensee performance in terms of potential safety. Based on prescribed thresholds, the indicators will be classified by color representing varying levels of performance and incremental degradation in safety: GREEN, WHITE, YELLOW, and RED. GREEN indicators represent performance at a level requiring no additional NRC oversight beyond the baseline inspections. WHITE corresponds to performance that may result in increased NRC oversight. YELLOW represents performance that minimally reduces safety margin and requires even more NRC oversight. And RED indicates performance that represents a significant reduction in safety margin but still provides adequate protection to public health and safety.

The assessment process integrates performance indicators and inspection so the agency can reach objective conclusions regarding overall plant performance. The agency will use an Action Matrix to determine in a systematic, predictable manner which regulatory actions should be taken based on a licensee's performance. The NRC's actions in response to the significance (as represented by the color) of issues will be the same for performance indicators as for inspection findings. As a licensee's safety performance degrades, the NRC will take more and increasingly significant action, which can include shutting down a plant, as described in the Action Matrix.

More information can be found at: http://www.nrc.gov/NRR/OVERSIGHT/index.html.

SUMMARY OF FINDINGS

IR 05000373-00-06, IR 05000374-00-06, on 05/06-06/30/2000; Commonwealth Edison Company; LaSalle County Station; Unit 1 & 2; Resident Operations Report.

The report covers an 8-week period of resident inspection. The inspection was conducted of the following baseline activities: Adverse Weather Protection, Equipment Alignment, Fire Protection, Licensed Operator Requalification, Maintenance Rule Implementation, Maintenance Risk/Emergent Work, Non-Routine Evolutions, Operability Evaluations, Operator Workarounds, Permanent Plant Modifications, Post Maintenance Testing, Surveillance Testing, Temporary Plant Modifications, Emergency Action Level and Emergency Plan Changes, Performance Indicator Verification, and Event Followup. The inspection was conducted by resident inspectors, a regional emergency preparedness specialist, a regional reactor inspector, and a regional project engineer.

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, and Emergency Preparedness

- There were no findings identified.

Report Details

Summary of Plant Status: Both units operated at or near full power until June 22, 2000, when Unit 2 automatically shutdown due to low reactor vessel water level caused by a feedwater transient. Operators subsequently restarted Unit 2 and synchronized the unit to the grid on June 24, 2000. Both units operated at or near full power for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, and Emergency Preparedness

1R01 Adverse Weather Protection

a. Inspection Scope

The inspectors verified that the design features and licensee procedures protecting systems from the effects of hot weather and high winds were adequate. The inspectors focused on the station auxiliary transformers (SATs) and Residual Heat Removal (RHR) system. The inspectors reviewed the Updated Final Safety Analysis Report (UFSAR), and other documentation and verified that the plant was adequately protected from the effects of hot weather and high winds. The inspectors reviewed LaSalle abnormal operating procedures (LOAs) such as LOA-TORN-001, "High Winds/Tornado," Revision 2; and LOA-DIKE-001, "Lake Dike Damage/Failure," Revision 1, and verified that prescribed operator actions were appropriate to maintain readiness of essential systems to the maximum extent practicable. The inspectors reviewed LaSalle Station Emergency Plan Implementation Procedure (LZP) 1200-01, "Classification of GSEP [General Station Emergency Procedure] Conditions," Revision 23, and verified that appropriate entry conditions for adverse weather, such as tornadoes and flooding, existed. The inspectors reviewed the LaSalle Summer 2000 Readiness Plan for the SATs and RHR system and verified that the plan assessed potential items that could affect unit operation during the summer. The inspectors verified that scheduled critical maintenance was completed and that non-critical maintenance which was not completed was accurately identified. The inspectors reviewed the impact of leaking safety relief valves on the ability to maintain the suppression pool temperature within Technical Specification (TS) limits and verified adequate plant response in the event of a loss-of-coolant-accident during suppression pool cooling operation.

b. Issues and Findings

There were no findings identified.

1R04 Equipment Alignment

a. Inspection Scope

On May 11, the inspectors performed a partial walkdown of accessible portions of the Unit 1 High Pressure Core Spray (HPCS) system to verify system operability. This walkdown was performed after the licensee determined that the Unit 1 Reactor Core Isolation Cooling (RCIC) system was inoperable due to partially voided injection piping. That portion inside containment was not accessible. The inspectors verified against the system piping and instrumentation drawing (P&ID) M-95 and HPCS system mechanical checklist, the correct valve position of all major valves in the primary system flowpath and verified breaker alignments using the HPCS system electrical checklist.

The inspectors also performed a partial walkdown of accessible portions of the Unit 1 and Unit 2 Emergency Diesel Generator (EDG) systems to verify system operability during maintenance on the Division I, "0" EDG (swing diesel for both units). The inspectors performed the walkdown on the following systems:

Unit 1: Division II "A" EDG - dedicated EDG for Unit 1
Division III "B" EDG - dedicated EDG for Unit 1 HPCS

Unit 2: Division II "A" EDG - dedicated EDG for Unit 2
Division III "B" EDG - dedicated EDG for Unit 2 HPCS

The inspectors verified the correct valve position of valves in the primary system flowpath using the system P&ID and system mechanical checklist and verified breaker alignments using the system electrical checklist. The inspectors also observed instrumentation valve configurations and appropriate meter indications. The inspectors verified by direct observation the lubrication and cooling of major components. The inspectors verified proper installation of hangers and supports during the walkdown and verified operational status of support systems by direct observation of various parameters. The inspectors observed control room switch positions for the EDG systems. The inspectors also evaluated other conditions such as adequacy of housekeeping, the absence of ignition sources, and proper labeling of components.

b. Issues and Findings

There were no findings identified.

1R05 Fire Protection

a. Inspection Scope

The inspectors walked down the following Unit 1 and Unit 2 risk-significant areas to identify fire protection degradations:

Zone 5D1: Unit 1 Division III (HPCS) Switchgear Room and 125 Volt Direct Current (VDC) Battery Rooms
Zone 5D2: Unit 2 Division III (HPCS) Switchgear Room and 125VDC Battery Room

Zone 4F1:	Unit 1 Division I Switchgear Room, 125VDC and 250VDC Battery Rooms
Zone 4F2:	Unit 2 Division I Switchgear Room, 125VDC and 250VDC Battery Rooms
Zone 4E3:	Unit 1 Division II Switchgear Room and 125VDC Battery Room
Zone 4E4:	Unit 2 Division II Switchgear Room and 125VDC Battery Room
Zone 7B1:	Unit 1 HPCS Diesel Generator Room
Zone 7B2:	Unit 1 Division 2 Standby Diesel Generator Room
Zone 7B3:	Unit 1 Division 1 Standby Diesel Generator Room
Zone 7B4:	Unit 1 HPCS Diesel Day Tank Room
Zone 7B5:	Unit 1 Division 2 Diesel Day Tank Room
Zone 7B6:	Unit 1 Division 1 Diesel Day Tank Room
Zone 2G:	Unit 1 Reactor Building 710' Elevation
Zone 2F:	Unit 1 Reactor Building 740' Elevation

Emphasis was placed on control of transient combustibles and ignition sources; the material condition, operational lineup, and operational effectiveness of the fire protection systems, equipment, and features; and the material condition and operational status of fire barriers used to prevent fire damage or fire propagation.

In particular, the inspectors verified that all observed transient combustibles were being controlled in accordance with the licensee's administrative control procedures. In addition, the inspectors observed the physical condition of fire detection devices, such as overhead sprinklers, and verified that any observed deficiencies did not impact the operational effectiveness of the system. The physical condition of portable fire fighting equipment, such as portable fire extinguishers, was also observed and verified to be located appropriately and that access to the extinguishers was unobstructed. The inspectors verified fire hoses were installed at their designated locations and the physical condition of the hoses was verified to be satisfactory and access unobstructed. The physical condition of passive fire protection features such as fire doors, ventilation system fire dampers, fire barriers, fire zone penetration seals, and fire retardant structural steel coatings was inspected and verified to be properly installed and in good physical condition.

b. Issues and Findings

There were no findings identified.

1R11 Licensed Operator Requalification

a. Inspection Scope

On May 22, the inspectors observed licensed operator requalification simulator training scenario SEG [Simulator Exercise Guide] 00C3-01, which required that power be reduced from 100 percent to less than 25 percent within 2 hours to address a failed fuse affecting turbine stop valve fast closure capability. The inspectors verified crew performance in terms of clarity and formality of communication; the ability to take timely action in the safe direction; the prioritizing, interpreting, and verifying of alarms; the correct use and implementation of procedures, including alarm response procedures; timely control board operation and manipulation, including high-risk operator actions; the oversight and direction by the shift manager, including the ability to identify and implement appropriate TS actions such as reporting and emergency plan actions and notifications; and the group dynamics.

b. Issues and Findings

There were no findings identified.

1R12 Maintenance Rule Implementation

a. Inspection Scope

The inspectors reviewed the implementation of the maintenance rule requirements including a review of scoping, goal-setting, and performance monitoring, short-term and long-term corrective actions; and current equipment performance status. The systems selected for inspection were all classified as risk significant by the maintenance rule program and included RCIC, residual heat removal service water, RHR, and containment monitoring. The RCIC system was selected based upon recent performance problems discussed in this report as well as Inspection Report 50-373/2000004; 50-374/2000004. The containment monitoring system was selected since it had been categorized as an (a)(1) system. The remaining systems, categorized as (a)(2), were selected based upon their relatively high risk achievement worth contribution.

The inspectors independently verified the licensee's implementation of maintenance rule requirements for these systems by verifying that these systems were properly scoped within the maintenance rule; that all failed structures, systems, or components (SSCs) were properly categorized and classified as (a)(1) or (a)(2); that performance criteria for SSCs classified as (a)(2) were appropriate; and that the goals and corrective actions for SSCs classified as (a)(1) were appropriate. The inspectors also verified that issues were identified at an appropriate threshold and entered in the corrective action program. With regard to the residual heat removal service water and residual heat removal systems, the inspectors verified that availability and functional failure data was accurate through a review of operator log entries, out-of-services, and work request documentation.

b. Issues and Findings

There were no findings identified.

1R13 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

The inspectors reviewed the licensee's evaluation of plant risk, scheduling, configuration control, and performance of maintenance associated with planned and emergent work activities and verified that scheduled and emergent work activities were adequately managed. In particular, the inspectors reviewed the licensee's program for conducting maintenance risk safety assessments and verified that the licensee's planning, risk management tools, and the assessment and management of online risk were adequate.

The inspectors also verified that licensee actions to address increased online risk during these periods, such as establishing compensatory actions, minimizing the duration of the activity, obtaining appropriate management approval, and informing appropriate plant staff, were accomplished when online risk was increased due to maintenance on risk-significant SSCs. In particular, the inspectors reviewed the increase in risk due to the inoperability of the 2A RHR system for planned maintenance activities and verified that the actions to address the increased risk were consistent with licensee procedures. The inspectors also reviewed the contribution to risk incurred due to the unavailability of the Unit “0" station air compressor due to planned maintenance. This effort also included a review of probabilistic risk assessment data related to the contribution of the loss of instrument air initiating event to core damage frequency.

The inspectors also reviewed emergent work activities associated with 1E51-F013, “Unit 1 RCIC Injection Valve,” including the re-scheduling of surveillance tests, to verify that the licensee had taken the necessary steps to plan and control the work and the schedule revision. The inspectors determined that the addition of the emergent work associated with the RCIC system only had a small impact on the online risk assessment results for the period during which the work was planned, and that the rescheduled surveillance testing was adequately planned to minimize overall risk.

On June 4, the inspectors observed emergent work activities associated with monthly turbine control valve testing in accordance with LaSalle Operating Surveillance (LOS) RP-M5, “Turbine Control Valve Monthly Testing,” Revision 2. During the surveillance, unexpected problems with a control valve fast acting solenoid and a limit switch occurred. Analysis of the fast acting solenoid problem required a heater bay entry at power and a reduction in core thermal limits.

On June 6, following removal from service of a Unit 2 annunciator power supply for scheduled maintenance, the control room received approximately 20 alarms associated with Division II inverters 5 and 6. The inspectors observed licensee formulation and execution of a troubleshooting plan and restoration of Division II annunciator operability. The inspectors also reviewed actions taken by the licensee to ensure the operability of the Unit 2, Division I annunciators during the Division II troubleshooting effort.

b. Issues and Findings

There were no findings identified.

1R14 Nonroutine Plant Evolutions

a. Inspection Scope

The inspectors observed the implementation of LaSalle Special Procedure (LLP) 00-007, “Filling RCIC Downstream of 1E51-F013.” The inspectors also observed the implementation of portions of LaSalle Special Test Procedure (LST) 2000-05, “Unit 1 - Uprate Power Ascension Special Test Procedure,” Revision 1 and LST-2000-07, “Unit 2 - Uprate Power Ascension Special Test Procedure,” Revision 1.

LLP-00-007

As discussed in Inspection Report 50-373/2000004(DRP); 50-374/2000004(DRP), on February 29, 2000, during the performance of quarterly RCIC system testing in accordance with LOS-RI-Q5, operators identified a leak associated with 1E51-F013, the Unit 1 RCIC injection valve. Subsequently, Operability Evaluation 00-001, Revision 4, dated May 5, 2000, was approved and documented that the system was operable provided that RCIC injection line pressure was at least 30 pounds per square inch (psi) above reactor pressure.

On May 11, during a shiftly measurement of RCIC injection line pressure, operators identified that injection line pressure was only 29 psi above reactor pressure. This indicated that water level in the injection line had decreased to below the pre-established operability limit of 69 feet. As a result, the Unit 1 RCIC system was declared inoperable and unavailable pending further evaluation.

On May 11 and May 12, operations personnel performed LLP-00-007 which injected water into the RCIC injection line to raise water level to above the operability limit of 30 psi. The inspectors reviewed this procedure and observed the evolution on May 12. Subsequently, operators declared the RCIC system operable and continued to perform this evolution periodically until the valve was repaired during the week of May 29.

LST-2000-05

On May 9, 2000, the NRC approved and issued amendment 140 to Facility Operating License NPF-11 which authorized a 5 percent power uprate from 3323 megawatts thermal to 3489 megawatts thermal on Unit 1. On May 17 through May 21, operations personnel increased reactor thermal power in daily one percent increments and monitored critical equipment parameters in accordance with LST-2000-05. The inspectors reviewed LST-2000-05, observed portions of the power uprate activities, and reviewed critical equipment parameter data to verify that all plant equipment operated as expected and any deficiencies were addressed appropriately.

LST-2000-07

On May 9, 2000, the NRC approved and issued amendment 125 to Facility Operating License NPF-18 which authorized a 5 percent power uprate from 3323 megawatts thermal to 3489 megawatts thermal on Unit 2. On May 29 through June 8, operations personnel increased reactor thermal power in small increments, and monitored critical equipment parameters in accordance with LST-2000-07. The inspectors reviewed LST-2000-07, observed portions of the power uprate activities, and reviewed critical equipment parameter data to verify that all plant equipment operated as expected and any deficiencies were addressed appropriately.

b. Issues and Findings

There were no findings identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the technical adequacy of operability evaluations (OEs) to ensure that operability was properly justified. The inspectors reviewed the following operability evaluations:

OE 00-001, Revision 4

Revision 4 to OE 00-001 concluded that RCIC system operability was assured as long as water level in the RCIC injection line was maintained greater than 69 feet above the centerline of 1E51-F013, the Unit 1 RCIC injection valve. As discussed in Inspection Report 50-373/200004(DRP); 50-374/200004(DRP), a body-to-bonnet leak associated with this valve had been previously identified. The inspectors verified that elevation calculations contained in Revision 4 to OE 00-001 adequately reflected the component and piping elevations referenced in plant isometric drawings to ensure that prescribed RCIC piping pressure operability limits were correct. The inspectors also verified that other calculation assumptions in the operability evaluation were conservative, and that when non-conservative assumptions were identified, they were not likely to adversely impact the conclusions in the operability evaluation. The inspectors verified, through a sampling of control room log data, that the measured leakage documented in the operability evaluation was correct.

OE 98003, Revision 0

This operability evaluation reviewed the condition of RHR keep-fill check valves 2E12-F451 and 2E12-F448. The check valves were identified to have a calcium deposit which impacted their ability to prevent backflow of water from the residual heat removal service water system to the nonsafety-related service water system.

OE 95003, Revision 0

This operability evaluation reviewed the retaining of a EDG operable with only a single bank of air receivers greater than or equal to the minimum required receiver pressure.

OE 95031, Revision 0

This operability evaluation reviewed Unit 1 reactor pressure vessel structural integrity as a result of erroneous vendor calculations concerning surveillance specimen chemical analyses. The evaluation concluded that the errors were conservative and that the existing Unit 1 pressure-temperature curves remained acceptable for use.

b. Issues and Findings

There were no findings identified.

1R16 Operator Workarounds

a. Inspection Scope

The inspectors reviewed operator workarounds (OWAs) and operator challenges (OCs) to identify any potentially adverse impact on the function of mitigating systems or the ability to implement an abnormal or emergency operating procedure. The following items were reviewed:

OWA 217/283, Turbine Oil System Temperature Control Valve Problems

This operator workaround identified that the turbine oil system temperature control valve controllers failed to automatically control turbine oil temperature during operation. As a result, operators were required to manually adjust Unit 1 and Unit 2 service water flow to the turbine oil coolers about once every 12 hours. The inspectors reviewed temporary modification 1-0140-98 which was installed to monitor turbine lube oil temperature using a data recorder. Design Change Package (DCP) 9800279 to permanently correct this problem was scheduled for installation in October 2000.

OWA 236/264/265, EDG Penthouse Fire Alarms

This operator workaround identified that when any of the five emergency diesel generators were run and certain wind conditions existed, a fire alarm for the diesel generator penthouse/ventilation room was received. The alarm was caused by diesel exhaust fumes recirculating into the diesel generator air intake room. The licensee planned permanent design changes (DCPs 9900142, 9900143, and 990144) to prevent the exhaust fume recirculation in the vicinity of the ventilation room fire detectors.

OC 307, 2B Control Room Radiation Monitor 2D18-K751B Failed Downscale

This operator challenge concerned personnel actions to insert a trip signal in accordance with TS requirements when radiation monitor 2D18-K751B failed downscale.

OC 197, Loss of Meteorological Tower Differential Temperature Indication 33 to 375/200 Feet

This operator challenge concerned meteorological tower differential temperature indications for the 33 to 200 foot and 33 to 375 foot elevations. Both indications occasionally pegged upscale during the late evening and early morning hours when temperature inversions greater than the range of the installed instrumentation occurred. The inspectors verified that DCP 9900270 had been initiated and work scheduled to broaden the differential temperature indication range of the existing equipment.

b. Issues and Findings

There were no findings identified.

1R17 Permanent Plant Modifications

a. Inspection Scope

The inspectors reviewed DCP 9900272, "1E51-F013 Valve Replacement" and DCP 9900350, "Seal Weld Bonnet Leak on 1E51-F387 (formerly labeled 1E51-F013)." As discussed in Section 1R13 of Inspection Report 50-373/2000004(DRP); 50-374/2000004(DRP), Unit 1 RCIC injection valve 1E51-F013 had developed a pressure seal bonnet leak. The valve was an American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Section III, Class 1 valve that was part of the reactor coolant pressure boundary and a primary containment isolation valve. Design change package 9900272 installed a new valve upstream of 1E51-F013, functionally replacing the valve. Design change package 9900350 seal welded the valve bonnet-retaining ring to isolate the pressure seal bonnet leak.

The inspectors reviewed the DCPs and observed several repair and modification activities in the field. In particular, the inspectors verified that the Code and safety classification of the replaced structures, systems, and components (SSCs) was consistent with the design basis; affected operations procedures and training were identified; pressure boundary integrity was not compromised; and the modified SSC impact on seismic evaluations was acceptable. The inspectors also verified through a review of post-modification design assumptions, post-modification testing results, and non-destructive testing inspection results that the post-modification testing was adequate.

b. Issues and Findings

As part of DCP 990272, the ASME Class 1 pressure boundary was extended by about 8 feet upstream of the original 1E51-F013 valve. Since the piping between the new and original 1E51-F013 valve was part of the Class 1 pressure boundary, the existing 8-foot section of piping was upgraded from ASME Class 2 to ASME Class 1. Section IWA-7210(a) of the ASME Section XI inspection code required that the upgraded portion of piping and any additional material meet the technical, material, design, fabrication, and examination requirements of the original construction code. In this case, the applicable original construction code was ASME Section III, Division 1 - Subsection NB, 1974 edition, which required the section of piping being upgraded to be examined by either ultrasonic, eddy current, or radiographic testing of the entire volume, or magnetic particle/dye penetrant testing (MT/PT) of external surfaces and accessible internal surfaces. The licensee completed the upgrade of the section of piping on May 25, 2000.

During review of the upgrade evaluation, the inspectors questioned the licensee's conclusion that an MT/PT examination of accessible internal surfaces of piping subassembly RI-1048C was not required once the pipe had been cut to install the new 1E51-F013 valve. In the upgrade evaluation, the licensee had concluded that since the upgraded section of pipe was intact when the upgrade evaluation was completed and no internal surfaces were accessible during that specific time frame, only an MT/PT examination of the exterior surfaces of the piping section was required. The inspectors disagreed with the licensee's conclusion that upgrade evaluation activities completed on

May 25 were a separate and distinct event from the repair and installation activities of the new valve completed on May 31. The inspectors considered that the efforts to repair the leaking pressure bonnet seal on the 1E51-F013 valve effectively began on April 10, 2000, when the inspectors had identified water hammer concerns associated with the leak which continued through the end of the repair activities. Since the inspectors disagreed with the licensee's position with respect to the required piping inspections, this issue will be sent, via Task Interface Agreement (TIA), to NRR for guidance and interpretation. The TIA will be sent to NRR in accordance with the guidance specified in NRC Inspection Manual, Part 9900; Technical Guidance "American Society of Mechanical Engineers Boiler and Pressure Vessel Code, Sections III and XI."

Based on the inspectors observation and question concerning the ASME Section III NB-2551(a)(3) requirements, the licensee performed an expanded ultrasonic examination of the same area that would have been examined had the MT/PT examination of the internally accessible surfaces of the upgraded section of pipe been performed when the pipe was cut. No flaws were identified during the ultrasonic expanded ultrasonic examination.

The NRC requires more information to determine whether the issue in question is an acceptable item. Pending NRR guidance and interpretation, via TIA, this is an unresolved item (50-373; 374/00-006-01{DRP}). The licensee entered the issue into the station's corrective action process via PIF L2000-03609.

1R19 Post-Maintenance Testing

a. Inspection Scope

The inspectors reviewed and observed post-maintenance testing following routine and emergent maintenance activities. These post-maintenance testing activities included:

- LOS-RH-Q1, Attachment 2B "Unit 2 RHR (LPCI) [Low Pressure Coolant Injection] and RHR Service Water Pump and Valve Inservice Test for Operational Conditions 1, 2, 3, 4, and 5" following completion of work request (WR) 990008577-01, "Change Oil in 2E12C002B RHR Pump."
- 2B EDG Overspeed During LOS-DG-M3
- Unit 0 Station Air Compressor WRs 9900887, 9901632, 9900797, 9900127, 9900451, 9800040, and 9900696.

During post-maintenance testing observations, the inspectors verified that the test was adequate for the scope of the maintenance work which had been performed and that the testing acceptance criteria were clear and demonstrated operational readiness consistent with the design and licensing basis documents. The inspectors also verified that the impact of the testing had been properly characterized during the pre-job briefing; the test was performed as written and all testing prerequisites were satisfied; and that the test data was complete, appropriately verified, and met the requirements of the testing procedure. Following the completion of the test, the inspectors verified that the test equipment was removed and that the equipment was returned to a condition in which it could perform its safety function.

On May 31 during post-maintenance testing conducted in accordance with LOS-DG-M3 following routine maintenance on the 2B EDG, the EDG experienced an overspeed condition and tripped. A licensee investigation concluded that an operator-in-training operating the fuel rack reacted improperly to a change in fuel rack position and caused the engine to overspeed. The inspectors reviewed the troubleshooting activities to return the EDG to service and verified that the prescribed testing was adequate to address the overspeed condition. A fast start and subsequent slow start were performed successfully. The inspectors verified that all potentially affected engine components, such as the governor rack and injector linkage, and governor cams, were inspected.

During the performance of LOS-RH-Q1 which was conducted following routine 2B RHR pump motor oil replacement, the inspectors independently verified adequate motor oil sight glass level prior to and during the post-maintenance test, and verified that the motor oil prescribed for replacement was consistent with vendor recommendations.

During the week of June 26, the inspectors observed post-maintenance testing associated with various Unit “0" station air compressor work activities including replacement of a station air cross-tie header valve, replacement of various instrument air solenoid valves, relief valve testing, replacement of air compressor starting controls, and air dryer tank inspections. During the post-maintenance testing observations, the inspectors verified that the test was adequate for the scope of the maintenance work performed and that the testing acceptance criteria was clear and demonstrated operational readiness of the Unit “0" station air compressor.

b. Issues and Findings

There were no findings identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors observed surveillance testing on risk-significant equipment and verified that the SSCs selected were capable of performing their intended safety function and that the surveillance tests satisfied the requirements contained in TSs, the UFSAR, and licensee procedures. During surveillance testing observations, the inspectors verified that the test was adequate to demonstrate operational readiness consistent with the design and licensing basis documents, and that the testing acceptance criteria was clear. The inspectors also verified that the impact of the testing had been properly characterized during the pre-job briefing; the test was performed as written and all testing prerequisites were satisfied; the test data was complete, appropriately verified, and met the requirements of the testing procedure; and that the test equipment range and accuracy was consistent with the application, and the calibration was current. Following the completion of the test, the inspectors verified that the test equipment was removed, and that the equipment was returned to a condition in which it could perform its safety function.

The following surveillance testing activities were observed:

- LOS-RH-Q1, Attachment 2D, “Unit 2A RHR System Operability and Inservice Test for RHR Service Water Pumps 2E12-C300A/B”
- LOS-DC-M3-C, “125 VDC [Volt Direct Current] Battery Checks”
- LOS-RI-Q5, “Unit 1 Reactor Core Isolation Cooling (RCIC) System Pump Operability, Valve Inservice Tests in Conditions 1, 2, and 3, and Cold Quick Start”
- LOS-DG-M2, “1A(2A) Diesel Generator Operability Test,” Revision 43
- LOS-HP-Q1, “HPCS [High Pressure Core Spray] System Inservice Test,” Revision 40

b. Issues and Findings

There were no findings identified.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed Temporary Modification 9900341 which installed a pressure gauge between RCIC check valves 1E51-F065 and 1E51-F066. The purpose of the pressure gauge was to continuously monitor pressure in the Unit 1 RCIC injection line to ensure a sufficient amount of water was present in the line to prevent damage to the RCIC system due to a hydraulic transient. In particular, the inspectors reviewed safety evaluation L00-0504 against the system design basis documentation, including the UFSAR; TSs; ASME Section XI, Article IWA-7000, “Replacements”; and Safety Guide 11, “Instrument Lines Penetrating Primary Reactor Containment.” The inspectors also verified that the temporary modification was installed in accordance with WR 990167061 and that pre-installation and post-installation testing was adequate to confirm that there was no unintended impact on the plant.

b. Issues and Findings

There were no findings identified.

1EP4 Emergency Action Level and Emergency Plan Changes

a. Inspection Scope

The inspectors reviewed revisions 6l, 6n, and 7 to the LaSalle County Nuclear Power Station Emergency Plan Site Annex, which were submitted by licensee letters dated August 14, 1998; February 2, 1999; and August 26, 1999, to verify that the changes did not decrease the effectiveness of the plan. The emergency plan revisions were submitted in accordance with 10 CFR 50.54(q).

b. Issues and Findings

There were no findings identified.

4. OTHER ACTIVITIES

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

4OA2 Performance Indicator Verification

a. Inspection Scope

The inspectors reviewed the following first quarter 2000 performance indicators for Unit 1 and Unit 2 utilizing the performance indicator definitions and guidance contained in Nuclear Energy Institute (NEI) 99-02, "Regulatory Assessment Indicator Guideline," Revision 0:

- Unplanned Scrams Per 7,000 Critical Hours
- Scrams With A Loss Of Normal Heat Removal
- Unplanned Power Changes Greater Than 20 Percent Per 7,000 Critical Hours

The inspectors reviewed Licensee Event Reports (LERs) and operator log entries to determine the number of scrams that occurred during the previous four quarters and compared that number to the number in the performance indicator. The inspectors also reviewed licensee Monthly Operating Reports and operator logs to verify the accuracy of the number of critical hours reported. The inspectors verified performance indicator results through independent calculation. The inspectors also reviewed the licensee's basis for crediting normal heat removal capability for each of the reported reactor scrams.

The inspectors reviewed Monthly Operating Report power history data, control room logs, and Performance Indicator data sheets to verify that the licensee had adequately identified the number of unplanned power changes greater than 20 percent that had occurred during the previous 4 quarters. The inspectors verified performance indicator results through independent calculations.

b. Issues and Findings

There were no findings identified.

4OA3 Event Followup

a. Inspection Scope

On June 22, 2000, the Unit 2 reactor automatically shutdown following a failure of the 2A turbine-driven reactor feedwater pump. In response to the event, the inspectors observed plant parameters and status, including mitigating systems/trains and fission product barriers; evaluated the performance of mitigating systems and licensee actions; and confirmed that the licensee properly reported the event as required by 10 CFR 50.72. The inspectors determined that all systems responded to the event as designed, the automatic shutdown was not complicated by material condition deficiencies associated with mitigation equipment, and that no human performance errors complicated the event response. Details of the event were communicated to the region-based risk analysts who determined that the event was of low risk-significance.

b. Issues and Findings

There were no findings identified.

4OA5 Meetings

Exit Meeting Summary

The inspectors presented the inspection results to Mr. C. Pardee and other members of licensee management at the conclusion of the inspection on June 30, 2000. The licensee acknowledged the findings presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

ComEd

C. Pardee, Site Vice President
D. Bost, Site Engineering Manager
K. Bartes, Nuclear Oversight Manager
G. Kaegi, Site Training Manager
R. Gilbert, Operations Manager
F. Spangenberg, Regulatory Assurance Manager
J. Pollock, System Engineering Manager
T. Conner, Assistant Design Engineering Supervisor
T. Gierich, Work Control Manager
J. Henry, Shift Operations Superintendent

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-373; 374/00-006-01	URI	ASME Class I Piping Inspections

Closed

None

Discussed

None

LIST OF ACRONYMS USED

ASME	American Society of Mechanical Engineers
DCP	Design Change Package
DRP	Division of Reactor Projects
EDG	Emergency Diesel Generator
GSEP	General Station Emergency Procedure
HPCS	High Pressure Core Spray
LER	Licensee Event Report
LLP	LaSalle Special Procedure
LOA	LaSalle Abnormal Operating Procedure
LOS	LaSalle Operating Surveillance
LPCI	Low Pressure Coolant Injection
LST	LaSalle Special Test Procedure
LZP	Emergency Plan Implementing Procedure
MT/PT	Magnetic Particle/Dye Penetrant Testing
NEI	Nuclear Energy Institute
OC	Operator Challenge
OE	Operability Evaluation
OWA	Operator Workaround
P&ID	Piping and Instrumentation Drawing
PERR	Public Electronic Reading Room
psi	pounds per square inch
RCIC	Reactor Core Isolation Cooling
RHR	Residual Heat Removal
SAT	Station Auxiliary Transformer
SDP	Significance Determination Process
SEG	Simulator Exercise Guide
SSC	Structure, System, or Component
TIA	Task Interface Agreement
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
VDC	Volts Direct Current
WR	Work Request