May 10, 2005

Mr. Christopher M. Crane
President and Chief Nuclear Officer
Exelon Nuclear
Exelon Generation Company, LLC
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: LASALLE COUNTY STATION, UNITS 1 AND 2
NRC INTEGRATED INSPECTION REPORT 05000373/2005002;
05000374/2005002

Dear Mr. Crane:

On March 31, 2005, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your LaSalle County Station, Units 1 and 2. The enclosed report documents the results of this inspection discussed on April 5, 2005, with the Site Vice President, Ms. Susan Landahl, and other members of your staff.

The inspection examined activities conducted under your license as they related to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

Based on the results of this inspection, four NRC-identified and three self-revealed findings of very low safety significance were identified. All of these findings also involved violations of NRC requirements. However, because the findings associated with these violations were of very low safety significance and because the issues were entered into the licensee's corrective action program, the NRC is treating these issues as Non-Cited Violations in accordance with Section VI.A.1 of the NRC's Enforcement Policy. Additionally, two licensee identified violations are listed in Section 4OA7 of this report.

If you contest the subject or severity of any Non-Cited Violation in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspectors' Office at the LaSalle County Station.

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Sincerely,

/RA/

Bruce L. Burgess, Chief
Branch 2
Division of Reactor Projects

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

Enclosure: Inspection Report 05000373/2005002; 05000374/2005002
w/Attachment: Supplemental Information

cc w/encl:
Site Vice President - LaSalle County Station
LaSalle County Station Plant Manager
Regulatory Assurance Manager - LaSalle County Station
Chief Operating Officer
Senior Vice President - Nuclear Services
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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-373; 50-374
License Nos:	NPF-11; NPF-18
Report No:	05000373/2005002; 05000374/2005002
Licensee:	Exelon Generation Company, LLC
Facility:	LaSalle County Station, Units 1 and 2
Location:	2601 N. 21st Road Marseilles, IL 61341
Dates:	January 1 through March 31, 2005
Inspectors:	D. Kimble, Senior Resident Inspector D. Eskins, Resident Inspector A. Klett, Engineering Inspector D. Melendez-Colon, Reactor Engineer M. Mitchell, Radiation Protection Specialist J. Neurauter, Engineering Inspector T. Ploski, Senior Emergency Preparedness Inspector R. Walton, Operator Licensing Examiner J. Yesinowski, Illinois Dept. of Emergency Management
Approved by:	Bruce L. Burgess, Chief Branch 2 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

IR 05000373/2005002, 05000374/2005002; 01/01/2005 - 03/31/2005; LaSalle County Station, Units 1 & 2; Fire Protection, Maintenance Risk Assessments and Emergent Work Control, Post-Maintenance Testing, Access Control to Radiologically Significant Areas, and Identification and Resolution of Problems Report.

The inspection was conducted by both resident and regional inspectors. The report covers a 3-month period of baseline resident inspection, and announced baseline inspections in emergency preparedness, radiation protection, and of the inservice inspection program. Seven Green findings and seven associated non-cited violations (NCVs) were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using NRC Inspection Manual Chapter (IMC) 0609 “Significance Determination Process” (SDP). Findings for which the SDP does not apply may be "Green," or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. Inspector-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. A finding of very low safety significance was self-revealed when sparks from hot work associated with the cutting of a 20-inch pipe in the 2B residual heat removal (RHR) corner room on February 16, 2005, ignited a small pile of absorbent cleaning material in the room. An associated NCV was also identified against Technical Specification 5.4.1(c) for failure to follow the existing plant fire protection procedure related to hot work and ignition control.

  The performance deficiency, identified during review of the event, involved two examples where licensee personnel failed to properly implement the established plant procedure governing hot work and ignition control. The finding was of more than minor significance in that it had a direct impact on the cornerstone objective. Specifically, the licensee’s performance deficiencies were directly responsible for an actual Class ‘A’ fire in the 2B RHR corner room on February 16, 2005. Because the finding involved Unit 2 in a cold shutdown condition, the inspectors determined it to be of very low safety significance (Green) and within the licensee’s response band. Corrective actions completed by the licensee include: focused coaching sessions with superintendents and general foremen of hot work personnel; meetings between the station’s Fire Marshal and contractor supervision to discuss hot work issues; and focused coaching sessions with fire watch personnel by contractor management conveying the message that the fire watch is ultimately responsible for the work location being and remaining in compliance with fire safety standards. The finding was determined to involve the cross-cutting aspect of human performance. (Sections 1R05.2 and 4OA4)

- Green. The inspectors identified a finding of very low safety significance and an associated NCV during review of corrective actions associated with a small fire in the 2B RHR corner room on February 16, 2005. The inspectors determined that the licensee had, during several opportunities, failed to take timely and effective corrective actions with respect to ignition control for hot work. This failure was determined by the inspectors to be contrary to the requirements of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action."

  In reviewing corrective actions for 2B RHR corner room fire, the inspectors identified a performance deficiency regarding inadequate corrective actions taken to control hot work activities. The inspectors determined that the finding was of more than minor significance in that it had a direct impact on an objective for the Initiating Event Cornerstone. The inspectors determined that the finding impacted minimally on the licensee's capability to reach and maintain cold shutdown conditions. Therefore, this finding had very low safety significance (Green) and was within the licensee's response band. Additional corrective actions planned by the licensee include a comprehensive common cause analysis to determine whether or not generic fire protection programmatic weaknesses exist. (Section 4OA2.1)

- Green. The inspectors identified a finding of very low safety significance and an associated NCV during a review of the licensee's assessment and management of the risk affiliated with maintenance on the 1A circulating water (CW) pump. The inspectors' review revealed that the licensee had failed to recognize and effectively manage the risk associated with a meter replacement. The meter was in a circuit that was common to both the 1A CW pump, which was undergoing planned maintenance, and the 1C CW pump, which was in service. This failure to effectively assess and manage maintenance risk was determined by the inspectors to be contrary to the requirements of 10 CFR 50.65(a)(4).

  The performance deficiency with this issue was a failure on the part of the licensee to properly assess and manage the increase in risk from a planned maintenance evolution. The finding was of more than minor significance in that it had a direct impact on a Initiating Event Cornerstone objective. Specifically, the licensee's failure to properly assess and manage the increase in risk resulted in a plant transient that challenged the on-watch Operations crew. The inspectors determined this finding to be of very low safety significance (Green) because the finding did not contribute to both the likelihood of a transient and the likelihood that mitigation equipment or functions would not be available. Corrective actions completed by the licensee include: training to enhance worker proficiency at performing maintenance risk assessments on energized equipment, assessment of the existing production risk evaluation sheet used by work planners to determine if additional clarifications are required, discussion of this type of task at weekly work management meetings, reinforcement of Operations role in reviewing work on production risk systems, and evaluation of whether or not additional actions are required during clearance order preparations to preclude this type of event. The finding was determined to involve the cross-cutting aspect of human performance. (Sections 1R13.2 and 4OA4)

Cornerstone: Mitigating Systems

- Green. The inspectors identified a finding of very low safety significance and an associated NCV during a review of the licensee's assessment and management of the risk affiliated with the cycling of the 1DG032 manual gate valve. The gate valve was cycled during the performance of a scheduled '0' emergency diesel generator (EDG) auxiliaries inservice test on December 30, 2004. The inspectors' review revealed that the licensee had failed to recognize and effectively manage the risk associated with the operation of this valve. This valve was part of a group of manual gate valves located in essential service water systems that were known to be highly susceptible to disc/stem separation. This failure to effectively assess and manage the activity's risk was determined by the inspectors to be contrary to the requirements of 10 CFR 50.65(a)(4).

  The identified performance deficiency with this finding was a failure on the part of the licensee to have accurately assessed and properly managed the risk associated with the cycling of the 1DG032 manual gate valve. The finding was of more than minor significance in that it had a direct impact on an objective of the Mitigating Systems cornerstone. Specifically, the licensee's failure to properly assess and effectively manage the risk associated with the 1DG032 valve cycling evolution resulted in the interruption of supporting cooling water flow to Unit 1 Division 1 emergency core cooling system (ECCS) components, rendering these components inoperable and unavailable. Because the finding impacted only a single Division of the unit's ECCS; did not represent the loss of an entire system's safety function; did not result in a Technical Specification allowed outage time being exceeded; and the finding was not related to external events such as fire, flooding, or adverse weather; the inspectors concluded that the safety significance of this issue was very low (Green). Corrective actions completed by the licensee include: hanging tags on susceptible valves to warn personnel of the potential for stem/disc separation; validation of all essential service water valves susceptible to stem/disc separation and providing a listing of these components to plant operations; revision of applicable operating procedures to include a precaution that identifies the valves that are susceptible to stem/disc separation, and a requirement to verify the applicability of valves prior to operation. (Section 1R13.3)

- Green. A finding of very low safety significance was self-revealed when changes implemented by a modification to the Unit 2 125 volt direct current (Vdc) charger system were not appropriately incorporated into operational procedures. This procedural deficiency resulted in an under-voltage condition during an attempt to swap in-service chargers. An associated NCV against the requirements of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was also identified.

  The identified performance deficiency was the failure of the licensee to incorporate relevant design information concerning the metering circuitry of a newly installed battery charger into the appropriate operating procedures. The finding was of more than minor significance in that it had a direct impact on the

MS cornerstone objective. Specifically, the procedural deficiency, and lack of any formal training regarding the metering circuitry, contributed to a low voltage condition on the Unit 2 Division 1 125 Vdc system. The low voltage resulted in the Unit 2 Division 1 125 Vdc system being rendered inoperable for about 23 minutes. Because the finding involved the loss of only one train of safety related equipment and the loss was for less than the Technical Specification allowed outage time, the inspectors determined it to be of very low safety significance (Green) and within the licensee's response band. Corrective actions planned and completed by the licensee include: revision of applicable operating procedures; training for operations personnel on new charger procedures; and planned training to enhance operator knowledge regarding the metering circuitry and the differences between various battery chargers. (Section 1R19.2)

- Green. A finding of very low safety significance was identified by the inspectors. The licensee had failed during prior opportunities to fully evaluate the nature of the problem leading to various emergency diesel generator (EDG) reverse power trips. The most recent of these events were a reverse power trip of the 2B EDG on August 18, 2004, for which no root cause was ever determined, and a subsequent reverse power trip of the 2A EDG that occurred on December 7, 2004. An associated Non-Cited Violation (NCV) of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," was also identified by the inspectors.

  The performance deficiency was determined to be a failure on the part of the licensee's staff to fully evaluate a long standing issue with EDG reverse power trip. An evaluation in response to an event, as recent as August 18, 2004, failed to give sufficient priority to identified corrective actions in a manner that would preclude the latest occurrence, a reverse power trip of the 2A EDG on December 7, 2004. The finding was of more than minor significance in that it had a direct impact on the cornerstone objective. Specifically, the inspectors concluded that the licensee's performance deficiency was responsible for the reverse power trip of the 2A EDG on December 7, 2004, which caused the EDG to be unavailable for an additional 26 hours. Because the finding involved the loss of only one train of safety related equipment and the loss was for less than the Technical Specification allowed outage time, the inspectors determined it to be of very low safety significance (Green) and within the licensee's response band. Corrective actions planned and completed by the licensee include: establishment of a less restrictive EDG load limit to allow opening the EDG output breaker when the load is less than approximately 500 kW; additional training for licensed operators in the areas of EDG theory and operation and the effects of reverse power conditions on diesel generators; and revision of simulator modeling for EDGs to more accurately reflect actual plant performance for reverse power trips. (Section 4OA2.2)

Cornerstone: Occupational Radiation Safety

- Green. A finding of very low safety significance was self-revealed when an electrician improperly entered a high radiation area (HRA) in the radiation controlled area (RCA) (the Unit 2 drywell) that was posted as a HRA. This occurrence was revealed when he exited the RCA and the electronic dosimeter check-out was alerted that a dose rate alarm had occurred during the entry, revealing that the individual had signed on to the wrong radiation work permit (RWP).

The cause of the error was a failure to assure through self-checking that each entry to the electronic RWP sign-in is made using the correct RWP. The finding, under the Occupational Radiation Safety Cornerstone, does not involve the application of traditional enforcement because it did not result in actual safety consequences or potential to impact the NRC's regulatory function, and was not the result of any willful actions. The finding was more than minor as it involves the failure of the licensee to adhere to procedures to monitor and control radiation exposure, a key attribute under the objective of the radiation safety cornerstone to ensure adequate protection of worker health and safety from exposure to radiation. The finding is of very low safety significance because the individual was using an electronic dosimeter that alarms to warn workers of higher than expected dose rates or accumulated dose. The issue constituted a Non-Cited Violation of Technical Specification 5.7.1, which requires that access to, and activities in, each HRA with dose rates not exceeding 1.0 rem per hour at 30 centimeters from the radiation source be controlled by means of a RWP that includes specification of radiation dose rates in the immediate work area and other appropriate radiation protection equipment and measures. Immediate corrective actions included locking the individual out of the RCA and initiation of an investigation. Additionally, all site personnel were notified of this event through a station safety alert. The primary cause of the finding was related to the cross-cutting area of human performance. (Sections 2OS1.4 and 4OA4)

B. Licensee-Identified Violations

Violations of very low safety significance that were identified by the licensee have been reviewed by inspectors. Corrective actions planned or taken by the licensee have been entered into the licensee's corrective action program. These violations and corrective action tracking numbers are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1

The unit began the inspection period operating at full power. On February 5, 2005, power was reduced to approximately 65 percent to permit a control rod sequence exchange and control rod surveillance testing. The unit returned to operation at full power on February 6, 2005, and continued operating at or near full power for the remainder of the inspection period.

Unit 2

The unit began the inspection period operating at full power. On January 8, 2005, power was reduced to approximately 62 percent for a control rod pattern adjustment. Operation at full power was resumed on January 10, 2005. On February 7, 2005, the unit shut down for refueling outage L2R10. Unit 2 Cycle 11 achieved initial criticality following L2R10 on March 15, 2005, with full power being attained on March 18, 2005. On March 22, 2005, power was reduced briefly to approximately 65 percent to permit a control rod sequence exchange and control rod surveillance testing. The unit returned to full power operation later that same day, and continued operating 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 (71111.01)

Review of Site Specific Weather Condition – Tornado Warning

a. Inspection Scope

The inspectors performed an assessment of the licensee's preparations for adverse weather, including conditions that could lead to loss of off-site power and other conditions that could result from high winds or tornado-generated missiles. The licensee's procedures and preparations during a tornado warning in LaSalle County on March 30, 2005, were reviewed by the inspectors and were verified to be adequate. During the inspection, the inspectors focused on plant specific design features and the licensee's procedures used to respond to specified adverse weather conditions. Additionally, the inspectors reviewed the Updated Final Safety Analysis Report (UFSAR) and performance requirements for systems selected for inspection, and verified that operator actions were appropriate as specified by plant specific procedures.

This review constituted a single inspection sample.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

.1 Semiannual Complete System Alignment Verification

a. Inspection Scope

Due to the system's risk significance, the inspectors selected the Unit 1 core standby cooling system (CSCS) for a complete system alignment verification. The inspectors walked down the system to verify mechanical and electrical equipment lineups, component labeling, component lubrication, component and equipment cooling, hangers and supports, operability of support systems, and to ensure that ancillary equipment or debris did not interfere with equipment operation.

The inspectors' review of CSCS alignment constituted a single inspection sample.

b. Findings

No findings of significance were identified.

.2 Quarterly Partial System Alignment Verifications

a. Inspection Scope

The inspectors performed partial alignment verifications on the following equipment trains to verify operability and proper equipment lineup. These systems were selected based upon risk significance, plant configuration, system work or testing, or inoperable or degraded conditions.

- Unit 2 fuel pool cooling system while unit fuel pools were cross connected
- Unit 2 'B' residual heat removal low pressure core spray system
- Unit 2 'C' residual heat removal low pressure core spray system

The inspectors verified the position of critical redundant equipment and looked for any discrepancies between the existing equipment lineups and the required lineups.

These partial equipment alignment verifications constituted three inspection samples.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Quarterly Fire Protection Zone Inspections

a. Inspection Scope

To identify potential fire protection issues, the inspectors conducted field observations in the following risk significant areas. These areas were selected because of the systems, structures, or components designated as important to reactor safety that were located therein.

- Fire Zone 4E1, Unit 1 auxiliary equipment room
- Fire Zone 4E3, Unit 1 Division 2 essential switchgear room
- Fire Zone 4F1, Unit 1 Division 1 essential switchgear room
- Fire Zone 4F2, Unit 2 Division 1 electrical switchgear room
- Fire Zone 8B1, Unit 2 Division 3 emergency diesel generator room
- Fire Zone 8B2, Unit 2 Division 2 emergency diesel generator room
- Fire Zone 8C1, Unit 2 Division 3 emergency diesel generator fuel storage tank room
- Fire Zone 8C3, Unit 2 Division 3 emergency diesel generator cooling water pump room
- Unit 2 emergency diesel generator corridor

The inspectors reviewed the control of transient combustibles and ignition sources, fire detection equipment, manual suppression capabilities, passive suppression capabilities, automatic suppression capabilities, barriers to fire propagation, and any contingency fire watches that were in effect.

These quarterly fire protection inspections constituted nine inspection samples.

b. Findings

No findings of significance were identified.

.2 2B Residual Heat Removal (RHR) Corner Room Fire

a. Inspection Scope

The inspectors followed up on a small Class ‘A’ fire that occurred in the 2B RHR corner room as a result of hot work on February 16, 2005. The inspectors reviewed the control of transient combustibles and ignition sources, fire detection equipment, manual suppression capabilities, passive suppression capabilities, automatic suppression capabilities, barriers to fire propagation, and any contingency fire watches that were in effect. In addition, the inspectors reviewed the licensee’s apparent cause evaluation (ACE) for the event.

This review constituted a single inspection sample.

b. Findings

Introduction

A finding of very low safety significance (Green) was self-revealed when sparks from hot work associated with the cutting of a 20-inch pipe in the 2B RHR corner room ignited a small pile of absorbent cleaning material in the room. A Non-Cited Violation (NCV) of Technical Specification 5.4.1(c) for failure to follow the existing plant fire protection procedure related to hot work and ignition control was also identified.

A second finding and NCV associated with this event are described in Section 4OA2.1 of this report.

Description

On February 16, 2005, at approximately 2:30 p.m., work was in progress in the 2B RHR corner room to demolish a section of pipe that was slated for removal as part of an approved permanent plant modification. The work involved cutting a vertical run of 20-inch diameter pipe into sections that were approximately 1 foot in length to facilitate ease of removal. A single fire watch was assigned to the area where the cutting was taking place. Fire blanketing was placed in the area of the hot work, with additional material surrounding the floor piping penetration to prevent sparks from falling through the penetration. This fire blanket extended outward for approximately 8 feet from the work. During the course of the work, some of the sparks generated by the pipe cutting activities were thrown past the fire blanket and fell through open floor grating to the 694' elevation below.

At some point following lunch, cleaning material was staged on the 694' elevation below the area where the hot work was in progress. When interviewed as part of the licensee's ACE, the fire watch stated that he was not aware of the introduction of this combustible material to this area. Sparks that fell from the hot work above ignited a small Class 'A' fire in this material. A laborer in the area detected the fire and attempted to extinguish it by stepping on the flames. When this was not successful, a mop was used in an attempt to smother the flames. When this action, too, proved ineffective, the laborer notified the fire watch on the level above, who extinguished the fire with a dry chemical fire extinguisher. The control room was notified of the fire by the personnel involved in the 2B RHR corner room.

Unrelated to the actual fire itself, a problem was encountered with the dry chemical fire extinguisher used by the fire watch to combat the fire. In addition to being discharged from the nozzle as expected, dry chemical extinguishing agent was observed to emit from underneath the cap of the extinguisher. As noted above, despite this malfunction, the fire watch was able to use the extinguisher to successfully combat the fire. An investigation by the licensee subsequently determined that the malfunction was the result of a missing gasket normally installed under the fire extinguisher cap.

Analysis

The inspectors determined that there was a licensee performance deficiency associated with the fire blanket coverage provided for the job. Specifically, the coverage was inadequate in that it did not fully contain all the sparks being generated from the cutting activity, and was not in compliance with the licensee's established procedure governing hot work ignition controls. Procedure OP-MW-201-004, "Fire Prevention for Hot Work," Section 4.2, "Fire Prevention Precautions," required fire blanket coverage out to 35 feet from the work location. In this event, the fire blanket coverage went out a mere 8 feet. This lack of adequate fire blanket coverage was, in part, responsible for the sparks from the hot work reaching the open floor grating and falling to the 694' elevation below.

In addition, a second performance deficiency associated with the duties of the fire watch was identified. Procedure OP-MW-201-004, Section 3.4.2, discussed the duties of the fire watch, and required that each fire watch was responsible for stopping the hot work in the event of any safety problems, such as sparks coming in contact with combustible material, etc. At the time of the fire, the hot work in the 2B RHR corner room had been in progress for three shifts. The fire watches assigned to the job had ample opportunity to self-identify the spark hazard caused by the hot work and were required by procedure to do so.

The objective of the Initiating Events Cornerstone of Reactor Safety is "to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations." In accordance with NRC Inspection Manual Chapter (IMC) 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," the inspectors determined that the finding was of more than minor significance in that it had a direct impact on this cornerstone objective. Specifically, one of the key attributes associated with this cornerstone objective is protection against fires, and the inspectors determined that the licensee's performance deficiencies were directly responsible for an actual Class 'A' fire in the 2B RHR corner room.

The inspectors determined that the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," and conducted a Phase 1 characterization and initial screening. Because the finding was associated with fire protection, this was accomplished using IMC 0609, Appendix F, Attachment 1, "Fire Protection SDP Phase 1 Worksheet." Based on the size and location of the fire, the inspectors concluded it could only plausibly affect Unit 2, which was in cold shutdown. As a result, the inspectors determined that the finding only pertained to the ability to reach and maintain cold shutdown conditions, and was, therefore, of very low safety significance (Green) and within the licensee's response band. Because the finding involved the cross-cutting aspect of human performance, it is also noted in Section 4OA4, "Cross-Cutting Aspects of Findings," in this report.

Enforcement

Technical Specification 5.4.1(c) requires that written procedures for the station's fire protection program be established, implemented, and maintained. Contrary to this requirement, on February 16, 2005, licensee personnel conducting hot work in the 2B

RHR corner room failed to implement the following provisions of OP-MW-201-004, “Fire Prevention for Hot Work,” as specified:

- Section 4.2.1.4, “Openings or cracks in walls, floors, or ducts within 35 feet of the site shall be tightly covered to prevent the passage of sparks to adjacent areas;”
- Section 3.4.2, “The Fire Watch is responsible for stopping the hot work in the event of a safety problem (i.e., sparks coming in contact with combustible material, faulty equipment, etc.).

The licensee had entered this fire into their corrective action program (CAP) as Issue Report (IR) 302209. Similarly, the malfunction of the dry chemical fire extinguisher was entered into the CAP as IR 302447. Corrective actions completed by the licensee include: focused coaching sessions with superintendents and general foremen of personnel performing hot work; meetings between the station’s Fire Marshal and contractor supervision to discuss hot work issues; and focused coaching sessions with fire watch personnel by contractor management conveying the message that the fire watch is ultimately responsible for the work location being and remaining in compliance with fire safety standards. Because the licensee has entered the issue into their corrective action program and the finding is of very low safety significance, this violation of Technical Specification 5.4.1(c) is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy. (NCV 05000374/2005002-01)

1R08 <u>Inservice Inspection (ISI) Activities</u> (71111.08)

<u>Piping Systems ISI</u>

a. <u>Inspection Scope</u>

From February 7 to February 9, 2005, and from February 28 to March 1, 2005, inspectors conducted a review of the implementation of the licensee’s ISI program for monitoring degradation of the reactor coolant system boundary and the risk significant piping system boundaries for Unit 2. The inspectors selected the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Section XI required examinations and code components in order of risk priority as identified in Section 71111.08-03 of NRC inspection procedure (IP) 71111.08, “Inservice Inspection Activities,” based upon the ISI activities available for review during the onsite inspection period.

<u>(02.01.a and 02.01.b)</u>

The inspectors conducted an on-site review of the following types of nondestructive examination activities to evaluate compliance with the ASME Code Section XI and Section V requirements and to verify that indications and defects (if present) were dispositioned in accordance with the ASME Code Section XI requirements. Specifically, the inspectors observed the following examination:

- Magnetic particle examination of residual heat removal system piping line 2RH40CB-16-inch restraint RH40-2877X lug welds. Two recordable indications were identified and dispositioned in accordance with the ASME Code Section XI requirements.

The inspectors performed a record review for the following examination:

- Ultrasonic examination of reactor pressure vessel nozzle to shell weld LCS-2-N2B. No recordable indications were identified.

(02.01.c)

The inspectors reviewed examinations completed during the previous outage with relevant/recordable conditions/indications that were accepted for continued service to verify that the licensee's acceptance was in accordance with Section XI of the ASME Code. Specifically, the inspectors reviewed the following records:

- Five recordable indications found during ultrasonic examination of reactor pressure vessel weld LCS-2-BH;
- Ten recordable indications found during ultrasonic examination of reactor pressure vessel nozzle to shell weld LCS-2-N4D.

(02.01.d)

The inspectors reviewed pressure boundary welds for Code Class 1 or 2 systems which were completed during the previous refueling outage, to verify that the welding acceptance and preservice examinations (e.g., pressure testing and dye penetrant tests) were performed in accordance with the ASME Code Sections III, V, IX, and XI requirements. Specifically, the inspectors reviewed welds associated with the following work activity:

- Penetrant examination of welds for replacement of double block valves 2E12-F325B/326B with single block valves.

(02.05)

The inspectors performed a review of piping system ISI related problems that were identified by the licensee and entered into the CAP. The inspectors reviewed these CAP documents to confirm that the licensee had appropriately described the scope of the problems. Additionally, the inspectors' review included confirmation that the licensee had an appropriate threshold for identifying issues and had implemented effective corrective actions. The inspectors evaluated the threshold for identifying issues through interviews with licensee staff and review of licensee actions to incorporate lessons learned from industry issues related to the ISI program. The inspectors performed these reviews to ensure compliance with 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," requirements. The corrective action documents reviewed by the inspectors are listed in the attachment to this report.

All the reviews discussed above constituted a single inspection sample.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

a. Inspection Scope

The inspectors observed a training crew during an evaluated simulator scenario and reviewed licensed operator performance in mitigating the consequences of events. The scenario included a scram condition that resulted from a loss of coolant accident (LOCA). The training crew's response to this casualty was complicated by a simulated stuck open turbine bypass valve. Areas observed by the inspectors included: clarity and formality of communications, timeliness of actions, prioritization of activities, procedural adequacy and implementation, control board manipulations, managerial oversight, emergency plan execution, and group dynamics. Additionally, the inspectors observed the instructors' critique and evaluation of the training crew's performance.

This quarterly training observation constituted a single inspection sample.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed the licensee's handling of performance issues and the associated implementation of the Maintenance Rule (10 CFR 50.65) to evaluate maintenance effectiveness for the Unit 1 and Unit 2 standby liquid control (SBLC) systems. The systems were selected based on being designated as risk significant under the Maintenance Rule and due to inspector-identified issues that potentially could impact system work practices, reliability, or common cause failures.

The inspectors' review included verification of the licensee's categorization of specific issues, including evaluation of the performance criteria, appropriate work practices, identification of common cause errors, extent of condition, and trending of key parameters. Additionally, the inspectors reviewed the licensee's implementation of the Maintenance Rule requirements, including a review of scoping, goal-setting, performance monitoring, short-term and long-term corrective actions, functional failure determinations associated with the condition reports reviewed, and current equipment performance status.

This maintenance effectiveness review constituted a single inspection sample.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13)

.1 Routine Quarterly Inspections

a. Inspection Scope

The inspectors reviewed and observed emergent work, preventive maintenance, or planning for risk significant maintenance activities. The inspectors observed maintenance or planning for the following activities or risk significant systems undergoing scheduled or emergent maintenance:

- Water intrusion into Unit 1 core standby cooling system (CSCS) pump room ventilation control panels;
- Unit 1 drywell floor drain sump alternate fill up rate monitor failure upscale troubleshooting and repair;
- Unit 1 scram discharge volume ½ scram condition due to instrument failure;
- Unit 1 and Unit 2 Division 1 and 2 safeguards 4,160 Vac buses single point vulnerability.

The inspectors also reviewed the licensee's evaluation of plant risk, risk management, scheduling, and configuration control for these activities in coordination with other scheduled risk significant work. The inspectors verified that the licensee's control of activities considered assessment of baseline and cumulative risk, management of plant configuration, control of maintenance, and external impacts on risk. In-plant activities were reviewed to ensure that the risk assessment of maintenance or emergent work was complete and adequate, and that the assessment included an evaluation of external factors. Additionally, the inspectors verified that the licensee entered the appropriate risk category for the evolutions.

These reviews constituted four inspection samples.

b. Findings

No findings of significance were identified.

.2 1C Circulating Water (CW) Pump Trip During Maintenance

a. Inspection Scope

The inspectors reviewed the licensee's planning for work during a scheduled 1A CW pump maintenance period. Among the items reviewed were the licensee's evaluation of plant risk, risk management, scheduling, and configuration control for the scheduled activities, and coordination with other scheduled risk significant work. The inspectors verified that the licensee's control of activities considered assessment of baseline and cumulative risk, management of plant configuration, control of maintenance, and external impacts on risk. Additionally, the inspectors verified that the licensee entered the appropriate risk category for the planned maintenance tasks.

This review constituted a single inspection sample.

b. Findings

Introduction

The inspectors identified a finding of very low safety significance (Green) and an associated Non-Cited Violation (NCV) during a review of the licensee's assessment and management of the risk affiliated with maintenance on the 1A circulating water (CW) pump. The inspectors' review revealed that the licensee had failed to recognize and effectively manage the risk associated with a meter replacement in a circuit that was common to both the 1A CW pump, which was undergoing planned maintenance, and the in service 1C CW pump. This failure to effectively assess and manage maintenance activity risk was determined by the inspectors to be contrary to the requirements of 10 CFR 50.65(a)(4).

Description

On January 4, 2005, at approximately 1:05 p.m., the 1C CW pump tripped. A planned maintenance window for the 1A CW pump was in progress to allow plant electricians to replace the 1A CW pump's elapsed run time meter. An investigation by the licensee revealed that an actuation of the 1C CW pump's slip guard relay caused the trip. An electrical short generated during the 1A CW pump's elapsed run time meter replacement had caused the 1C CW pump's slip guard relay to actuate.

A licensee root cause review (RCR) of this event identified several human performance issues. First, the work planner for the meter replacement task incorrectly evaluated production risk when completing the station's production risk evaluation form for the work package. Second, the electrical maintenance first-line supervisor did not correctly perform the maintenance risk assessment for the task prior to executing the work. Third, the craft electricians actually performing the meter replacement task caused an electrical short that was the initiating event for the transient. Central to all of these errors was the fact that an unidentified common metering circuitry existed between the 1A and 1C CW pumps. This unidentified circuit caused a short circuit during the 1A CW pump's meter replacement to affect the running 1C CW pump. This common circuitry had not been identified by the work planner or by the electrical maintenance first-line supervisor during their respective risk assessments.

The trip of the 1C CW pump resulted in a slow loss of condenser vacuum, which translated into an approximate 30 Mwe loss in generation. Ultimately, the licensee reduced Unit 1 reactor power by approximately six percent in order to allow the operating crew to more easily deal with the event and the recovery from it.

Analysis

The inspector-identified performance deficiency with this issue was the failure on the part of various licensee staff members to accurately assess and properly manage the risk associated with replacement of the 1A CW pump's elapsed run time meter. Upon review of the event, the inspectors determined that sufficient information was available to identify the common circuitry between the 1A and 1C CW pumps. Consequently, the licensee should have had sufficient information to properly assess and manage the risk associated with 1A CW pump's elapsed run time meter replacement. In interviews with senior licensee staff members, the inspectors identified that had the vulnerability to the running 1C CW pump been better understood, managers probably would not have allowed the meter replacement to be performed with the unit on line, or, at a minimum, would have ensured that more controls and oversight were in place during the evolution.

The objective of the Initiating Events Cornerstone of Reactor Safety is "to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations." In accordance with NRC Inspection Manual Chapter (IMC) 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," the inspectors determined that the finding was of more than minor significance in that it had a direct impact on this cornerstone objective. Specifically, the licensee's failure to properly assess and effectively manage the risk associated with the 1A CW pump's elapsed run time meter replacement resulted in a transient to the unit that upset its stability and constituted an unwarranted operating challenge to the on-watch control room crew.

The inspectors determined that the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," and conducted a Phase 1 characterization and initial screening. Because the finding did not contribute to both the likelihood of a transient and the likelihood that mitigation equipment or functions would not be available, the inspectors determined it to be of very low safety significance (Green) and within the licensee's response band. Because the finding involves the cross-cutting aspect of human performance, it is also noted in Section 4OA4, "Cross-Cutting Aspects of Findings," in this report.

Enforcement

As described in the SDP station-specific notebooks for LaSalle Units 1 and 2 and the licensee's Maintenance Rule Program, the CW pumps are risk-significant components. Section (a)(4) of 10 CFR 50.65 states that before performing maintenance activities (including but not limited to surveillance, post-maintenance testing, and corrective and preventive maintenance), the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities. Contrary to this requirement, the licensee failed to properly assess and effectively manage the increase in risk associated with the replacement of the 1A CW pump's elapsed run time meter.

The licensee had entered this issue into their corrective action program as IR 287541. Corrective actions completed by the licensee included: administration of training to enhance worker knowledge and proficiency at performing maintenance risk assessments on energized equipment; assessment of the existing production risk evaluation sheet used by work planners to determine if additional questions and clarifications are required; discussion of this type of task at weekly work management meetings; and reinforcement of the Operations role in reviewing work on production risk systems. Because the licensee has entered the issue into their corrective action program and the finding is of very low safety significance, this violation of 10 CFR 50.65(a)(4) is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy. (NCV 05000373/2005002-02)

.3 Valve 1DG032 Disc/Stem Separation During Operation

a. Inspection Scope

The inspectors reviewed the planning associated with a scheduled ‘0’ emergency diesel generator (EDG) auxiliaries inservice test (IST) on December 30, 2004. Among the items reviewed were the licensee's evaluation of plant risk, risk management, scheduling, and configuration control for the activities performed,; and coordination with other scheduled risk significant work. The inspectors verified that the licensee’s control of activities considered assessment of baseline and cumulative risk, management of plant configuration, control of maintenance, and external impacts on risk. Additionally, the inspectors verified that the licensee entered the appropriate risk category for the work performed.

This review constituted a single inspection sample.

b. Findings

Introduction

The inspectors identified a finding of very low safety significance (Green) and an associated Non-Cited Violation (NCV) during a review of the licensee’s assessment and management of the risk affiliated with the cycling of the 1DG032 manual gate valve during the performance of a scheduled ‘0’ EDG auxiliaries inservice test on December 30, 2004. The inspectors’ review revealed that the licensee had failed to recognize and effectively manage the risk associated with the operation of this valve. This valve was part of a group of manual gate valves located in the plant’s essential service water systems that were known to be highly susceptible to disc/stem separation. This failure to effectively assess and manage the activity’s risk was determined by the inspectors to be contrary to the requirements of 10 CFR 50.65(a)(4).

Description

On December 30th, 2004, plant operators performed procedure LOS-DG-Q1, “0 Diesel Generator Auxiliaries Inservice Test,” Attachment A5, “0 Diesel Generator Cooling Water Pump ASME Section XI Test.” A pre-evolution briefing, held with two non-licensed operators (NLOs) included direction that if indicated cooling water flows were not within specification to return to the control room. The control room operators would then provide additional briefings to the NLOs on actions contained in the procedure intended to correct cooling water flow abnormalities.

Initial Unit 1 Division 1 cooling water flow rates were identified to be high and outside of the procedure's specified acceptance criteria. The on-watch Shift Manager was notified of the condition and engineering contacted for assistance. Based on discussions between engineering and operations personnel, it was determined that operators should continue in accordance with LOS-DG-Q1, Attachment A5, in an attempt to correct the out of specification cooling water flow. An additional NLO was assigned to assist with these activities. A second pre-evolution briefing was held with the three NLOs, followed by a briefing for the Unit 1 and Unit 2 operations control room crews. Items discussed during these briefings included applicable Technical Specification Required Actions (RAs) to be entered when specific valves were to be manipulated, the potential for stem/disc separation, and the potential for EDG cooling water flow to be high, above acceptable limits. Although operations personnel were not aware that the 1DG032 valve was specifically susceptible to stem/disc separation, it was well known within the licensee's organization that similar type valves in this system have had a history of such failures.

Valve 1DG032 controls flow through the northwest emergency core cooling system (ECCS) corner room area cooler, the northeast ECCS corner room area cooler, and the low pressure core spray (LPCS) motor cooler. Procedure LOS-DG-Q1 directed the NLOs to cycle this valve as part of a sequence of steps intended to perform a flush of system components in an attempt to restore cooling water flow rates to normal. The procedure contained no warnings or cautions against cycling the valve. Once in the field, the NLOs noted no signs or placards on the valve advising of any potential for stem/disc separation. Because of the lack of any specific guidance to the contrary, the operators concluded that it was acceptable to continue with the 1DG032 valve cycling evolution.

In accordance with the approved LOS-DG-Q1 procedure steps, the NLOs cycled the 1DG032 valve. Cooling water flow decreased from approximately 475 gpm to 0 gpm, and flow noises subsided. However, upon reopening the valve neither cooling water flow indication nor increased flow noise were noted. After on-watch shift supervisors were notified and a second attempt to cycle the valve was executed, operations personnel concluded that the 1DG032 valve had probably suffered a stem/disc separation.

The 1DG032 valve failure and interruption in cooling water flow resulted in the 1A RHR, LPCS, and reactor core isolation cooling (RCIC) systems being rendered inoperable. A subsequent licensee investigation identified that the 1DG032 valve is part of a group of components with known tendencies for stem/disc separation. Some of these valves have been replaced or repaired, some have failed and been abandoned (i.e., blank flanged, etc.), and some, such as was the case with the 1DG032 valve, had not been operated for years and their exact condition was not known. This information was contained within the licensee's computer database used to generate clearances/tagouts, as well as on engineering prints specifically created to highlight the susceptible components. Many members of the licensee's staff, such as cycle planners, system engineers, and work week managers, were aware of these susceptible components, but the specific information was not provided to plant operators or properly captured in procedures or other controlled reference documents.

Analysis

The inspector-identified performance deficiency with this issue was a failure on the part of the licensee to accurately assess and properly manage the risk associated with the cycling of the 1DG032 manual gate valve. Upon review of the event, the inspectors determined that sufficient written information was available to the licensee's organization that should have alerted plant operators to the risk involved with cycling 1DG032. In interviews with plant operators and other personnel, the inspectors identified that had the susceptibility for 1DG032 stem/disc separation been better understood, on-watch operations supervisors probably would not have allowed the evolution to have gone forward, or, at a minimum, would have ensured that more controls and oversight were in place during the evolution.

The objective of the Mitigating Systems Cornerstone of Reactor Safety is "to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage)." In accordance with NRC Inspection Manual Chapter (IMC) 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," the inspectors determined that the finding was of more than minor significance in that it had a direct impact on this cornerstone objective. Specifically, the licensee's failure to properly assess and effectively manage the risk associated with the 1DG032 valve cycling evolution resulted in the interruption of supporting cooling water flow to Unit 1 Division 1 ECCS components, rendering these components inoperable and unavailable.

The inspectors determined that the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," and conducted a Phase 1 characterization and initial screening. Because the finding only impacted a single Division of ECCS and did not represent the loss of any entire system's safety function, and because no Technical Specification allowed outage times were exceeded and the finding was not related to external events such as fire, flooding, or adverse weather, the inspectors determined it to be of very low safety significance (Green) and within the licensee's response band.

Enforcement

Section (a)(4) of 10 CFR 50.65 states that before performing maintenance activities (including but not limited to surveillance, post-maintenance testing, and corrective and preventive maintenance), the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities. Contrary to this requirement, the licensee failed to properly assess and effectively manage the increase in risk associated with cycling the 1DG032 manual gate valve. Specifically, this type of valve was known to be susceptible to stem/disc separation, posing the potential for increased risk when cycling the valve.

The licensee had entered this issue into their corrective action program as IR 286665. Corrective actions completed by the licensee include: hanging tags on susceptible valves to warn personnel of the potential for stem/disc separation; validation of all essential service water valves susceptible to stem/disc separation and providing a listing of these components to plant operations; revision of applicable operating procedures to

include a precaution that identifies the valves that are susceptible to stem/disc separation and a requirement to verify the applicability of valves prior to operation; and review of the issue as a potential operator challenge/workaround. Because the licensee has entered the issue into their corrective action program and the finding is of very low safety significance, this violation of 10 CFR 50.65(a)(4) is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy.
(NCV 05000373/2005002-03)

1R14 Operator Performance During Non-Routine Evolutions and Events (71111.14)

.1 Operator Response to 1C Circulating Water Pump Trip on January 4, 2005

a. Inspection Scope

The inspectors performed several hours of continuous control room observation to evaluate operator performance in coping with an unexpected trip of the 1C circulating water (CW) pump during a planned maintenance window for the 1A CW pump. The inspectors reviewed operator logs and plant computer data to determine how the unit responded and to verify that operator actions were appropriate, and consistent with operator training and plant procedures. The licensee's planned recovery actions, procedures, reactivity manipulation briefings, and contingency plans were also reviewed by the inspectors to identify any personnel performance issues. In addition, the inspectors verified that any problems encountered during the non-routine evolution were identified by the licensee, and appropriately entered into the corrective action program.

The observation of this non-routine evolution by the inspectors constituted a single inspection sample.

b. Findings

No findings of significance were identified.

.2 Operator Response to the Losses of Unit 2 Shutdown Cooling on February 7, 2005

a. Inspection Scope

The inspectors performed several hours of control room observation to evaluate operator performance in coping with two unplanned interruptions of shutdown cooling flow. The first occurred at 7:56 a.m. due to valve isolations resulting from a trip of the 'A' reactor protection system (RPS) power supply. The second occurred at 10:55 a.m. due to the failure of the reactor recirculation (RR) system 'B' loop discharge stop valve, F067B, to close after shutdown of the 'B' RR pump. The inspectors reviewed operator logs, vessel temperature traces, and plant computer data to determine unit conditions and to verify that operator actions were appropriate, and consistent with operator training and plant procedures. The licensee's planned recovery actions, procedures, reactivity manipulation briefings, and contingency plans were also reviewed by the inspectors to identify any personnel performance issues. In addition, the inspectors verified that any problems encountered during the non-routine evolution were identified by the licensee, and appropriately entered into the corrective action program.

The observation of this non-routine evolution by the inspectors constituted a single inspection sample.

b. Findings

No findings of significance were identified.

.3 Operator Response to the Identification of a Single Point Vulnerability Affecting Division 1 and Division 2 4,160 Vac Safety Related Power

a. Inspection Scope

The inspectors evaluated operator performance during the identification of a single point vulnerability affecting the 4,160 Vac safety related switchgear on both Division 1 and Division 2 on both LaSalle units. The inspectors reviewed operator logs, clearance orders, equipment status tags, and plant computer data to determine unit conditions and to verify that operator actions were appropriate, and consistent with operator training and plant procedures. The licensee's planned recovery actions, procedures, reactivity manipulation briefings, and contingency plans were also reviewed by the inspectors to identify any personnel performance issues. In addition, the inspectors verified that any problems encountered during the non-routine evolution were identified by the licensee, and appropriately entered into the corrective action program.

The observation of this non-routine evolution by the inspectors constituted a single inspection sample.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed the technical adequacy of the following operability evaluations to determine the impact on Technical Specifications, the significance of the evaluations, and to ensure that adequate justifications were documented:

- Degradation of Lisega snubber operating oil due to radiation exposure in the Unit 1 and Unit 2 drywells (OE 04-008);
- Unit 1 core standby cooling system (CSCS) pump room ventilation system following water intrusion into control panels;
- Evaluation to support the removal of standby liquid control (SBLC) containment isolation valves (CIVs) from the 10 CFR 50, Appendix J, Type C local leak rate testing (LLRT) program (EC 332208);
- Degraded cooling fans on Transformer 236Y (OE 04-007);
- L2R10 lost parts evaluations for the reactor vessel and connected primary systems (EC 354196 and EC 354344).

Operability evaluations were selected based upon the relationship of the safety-related system, structure, or component to risk.

These reviews constituted five inspection samples.

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (71111.16)

a. Inspection Scope

The inspectors reviewed an operator workaround involving the manual control of reactor building ventilation control dampers. The inspectors reviewed the workaround's potential to impact the operators' ability to maintain reactor building differential pressure below the Technical Specification limit and detect potential changes in secondary containment integrity.

This review represented a single inspection sample.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17)

a. Inspection Scope

The inspectors reviewed the following modifications to verify that the design basis, licensing basis, and performance capability of risk significant systems were not degraded by the installation of the modifications. The inspectors also verified that the modifications did not place the plant in an unsafe configuration.

- Unit 2 Division 2 residual heat removal service water (RHRSW) keep fill elimination (EC 342975) and stainless steel valve replacements (EC 343542)
- Unit 2 drywell permanent lead shielding installation (EC 332685)
- Unit 2 steam dryer lifting lug upper support removal (EC 353949)

The inspectors considered the design adequacy of the modification by performing a review, or partial review, of the modification's impact on plant electrical requirements, material requirements and replacement components, response time, control signals, equipment protection, operation, failure modes, and other related process requirements.

These reviews constituted three inspection samples.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19)

.1 Miscellaneous Post-Maintenance Testing Reviews

a. Inspection Scope

The inspectors selected the following post-maintenance activities for review. Activities were selected based upon the structure, system, or component's ability to impact risk.

- Unit 1 drywell floor drain sump alternate fill up rate monitor post repair testing and calibration
- Unit 1 rod position indication system testing following probe data receiver card replacement
- Unit 2 'A' RPS motor generator set testing following voltage regulator repairs

The inspectors verified by witnessing the test or reviewing the test data that post-maintenance testing activities were adequate for the above maintenance or repair activities. The inspectors reviews included, but were not limited to, integration of testing activities, applicability of acceptance criteria, test equipment calibration and control, procedural use and compliance, control of temporary modifications or jumpers required for test performance, documentation of test data, Technical Specification applicability, system restoration, and evaluation of test data. Also, the inspectors verified that maintenance and post-maintenance testing activities adequately ensured that the equipment met the licensing basis, Technical Specifications, and Updated Final Safety Analysis Report (UFSAR) design requirements.

These reviews constituted three inspection samples.

b. Findings

No findings of significance were identified.

.2 Unit 2 Division 1 125 V Battery Charger Return to Service Following Maintenance

a. Inspection Scope

The inspectors reviewed the post maintenance testing and the return to service of the Unit 2 Division 1 125 Vdc battery charger, 2DC09E, following maintenance activities on January 19, 2005 and January 28, 2005. Design changes to the 125 Vdc system were reviewed as well as maintenance and operations procedures for the 125 Vdc system. Inspectors evaluated licensee performance and knowledge level during operation of these chargers.

The observation of this post-maintenance test by the inspectors constituted a single inspection sample.

b. <u>Findings</u>

<u>Introduction</u>

A finding of very low safety significance was self-revealed when a design modification to the Unit 2 Division 1 125 Vdc charger system was not appropriately incorporated into operational procedures. This resulted in an under-voltage condition during an attempt to swap on-service chargers. An NCV of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," for failure to properly incorporate design changes into procedures for the 125 Vdc system, was identified.

<u>Description</u>

On January 19, 2005, during the return to service of the Unit 2 Division 1 125 Vdc charger, 2DC09E, following maintenance, a Division 1 125 Vdc bus undervoltage alarm was received. During the swap of the on-service charger, 2DC23E, with the oncoming charger, 2DC09E, the oncoming charger failed to pick up load. This resulted in a low voltage condition on the Division 1 125 Vdc bus and the subsequent inoperability of that bus. 2DC23E was restored as the on-service charger and the bus undervoltage alarms cleared. Total inoperability time for the Division 1 125 Vdc bus was approximately 23 minutes.

Troubleshooting was commenced to determine the cause of the failure. It was subsequently determined that a procedural problem with LOP-DC-01, "Battery Charger Startup and Shutdown," was the cause of this failure. Changes to the battery charger system since the last design modification had not been adequately incorporated into the procedures used to swap battery chargers, or into operator training lesson plans. Specifically, voltage metering on the 2DC09E battery charger tapped into the DC circuitry in a different location than similar metering on the existing 2DC23E battery charger. The differences in voltage metering taps between the two chargers resulted in plant operators being presented with different indications when swapping from 2DC09E to 2DC23E, as opposed to when swapping from 2DC23E to 2DC09E.

The procedure was revised and training for operators on the procedure revision was conducted. The 2DC09E charger was also tested with a load bank to verify it was operating properly.

On January 28, 2005, licensee personnel again attempted to swap 2DC09E with the on-service charger, 2DC23E. During the swap, multiple control room alarms were received because the oncoming charger bus voltage was too high. Though this did not result in the inoperability of the DC bus, it did result in the inoperability of several process radiation monitors (PRMs) and the Unit 2 off gas log pretreatment monitor. The inspectors observed the evolution and discussed the issue with plant operations personnel. The inspectors concluded that, although the licensee had revised the procedure for swapping chargers and trained operators on the specific revision, plant operators performing the actual charger swap were still unaware of the differences in voltage metering between the two battery chargers.

Analysis

The performance deficiency associated with this event was a failure on the part of licensee personnel to have incorporated relevant design information, specifically information regarding differences in voltage metering between 2DC09E and 2DC23E, into LOP-DC-01, “Battery Charger Startup and Shutdown.”

The objective of the Mitigating Systems Cornerstone of Reactor Safety is “to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage).” In accordance with NRC Inspection Manual Chapter (IMC) 0612, “Power Reactor Inspection Reports,” Appendix B, “Issue Screening,” the inspectors determined that the finding was of more than minor significance in that it had a direct impact on this cornerstone objective. Specifically, the inspectors concluded that the licensee’s performance deficiency was primarily responsible for a low voltage condition on the Unit 2 Division 1 125 Vdc system on January 19, 2005, which rendered this system inoperable for approximately 23 minutes.

The inspectors determined that the finding could be evaluated using the SDP in accordance with IMC 0609, “Significance Determination Process,” and conducted a Phase 1 characterization and initial screening. Because the finding involved the loss of only one train of safety related equipment and the loss was for less than the Technical Specification allowed outage time, the inspectors determined it to be of very low safety significance (Green) and within the licensee’s response band.

Enforcement

Table 3.2-1 of the licensee’s Updated Final Safety Analysis Report (UFSAR) indicated that the 125 Vdc battery chargers are subject to the requirements of 10 CFR 50, Appendix B. Criterion V, “Instructions, Procedures, and Drawings,” of this appendix states, in part, that: “Activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, and drawings.” Contrary to this requirement, the licensee, by not incorporating relevant information concerning battery charger voltage metering into the procedure for swapping battery chargers, failed to properly prescribe an activity affecting quality, the swapping of battery chargers, into the station’s instructions and procedures for this task.

The licensee had entered this issue into their corrective action program as IR 287541. Corrective actions planned and completed by the licensee include: revision of LOP-DC-01 and training for operations personnel on new charger procedures. Because the licensee has entered the issue into their corrective action program and the finding is of very low safety significance, this violation of 10 CFR 50 Appendix B, Criterion V, is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy. (NCV 05000374/2005002-04)

.3 Unit 1 Core Standby Cooling System (CSCS) Pump Room Ventilation System Control Cabinet Water Intrusion

a. Inspection Scope

The inspectors reviewed repairs and testing of the Unit 1 Division 1 and Division 2 CSCS pump room ventilation system after water intrusion into the conduit system resulted in erratic behavior of the Unit 1 Division 2 temperature controller. Repairs to the controller and conduit system were inspected, including the method and effectiveness of sealing the conduit to prevent further water intrusion.

The observation of this post-maintenance test by the inspectors constituted a single inspection sample.

b. Findings

No findings of significance were identified. One unresolved item (URI) was identified.

On January 3, 2005, during a rain/snow shower, the control room received a high temperature alarm for the Unit 1 Division 2 CSCS pump room ventilation system (VY). The room temperature controller, 1TIC-VY024, was indicating 120 degrees. Actual room temperature was verified to be 73 degrees. The erratic behavior of this temperature controller resulted in the potential loss of temperature control for the Division 2 CSCS pump room and, consequently, the inoperability of the ‘C’ and ‘D’ RHRSW pumps and the ‘B’ spent fuel pool cooling (FC) emergency makeup pump. In January 2003, this same temperature controller had failed and had been replaced. The cause of this failure was never established.

Subsequent to the adverse weather on January 3, 2005, the 1TIC-VY024 controller was replaced with a new controller, but still continued to exhibit erratic behavior. The original controller was reinstalled and it was noted during troubleshooting that water dripping into the control panel from an internal conductor onto a terminal strip was causing stray currents which resulted in the erratic behavior of this controller. Further investigation revealed water intrusion inside the conduit connected to this control panel. Corrosion and standing water were also located in junction box 1JB301A associated with this conduit.

On January 5, 2005, repairs were performed to clean and dry the Division 2 VY conduit system and clean, paint, and drill weep holes in junction box 1JB301A . An extent-of-condition walkdown by the licensee noted that the Division 1 VY conduit and control panel also exhibited signs of water intrusion. Long term rust deposits and water dripping within the control panel were observed. This division was not considered inoperable due to a wiring configuration difference between the Division 1 and Division 2 control panels that directed dripping water within the panel away from the terminal strip. This wiring practice was commonly termed as “installing drip loops” and was required for cable terminations of this type per licensee maintenance procedures.

On January 9, 2005, the licensee made repairs to the Division 1 VY conduits in an attempt to stop the water intrusion by sealing the conduit. On February 15, 2005, during a rain shower, inspectors in the plant identified water dripping from weep holes in the Division 1 VY junction boxes from conduit that had supposedly been sealed several days earlier to prevent such water intrusion.

On March 25, 2005, during a rain shower, inspectors again identified water dripping from junction boxes on both Division 1 and Division 2 VY conduits that had previously been repaired for similar water intrusion events.

At the time of the writing of this report, the inspectors had challenged licensee engineering and maintenance personnel with several questions related to this issue. In response, the licensee had entered multiple items associated with this event into their corrective action program (IRs 287742, 287334, 287987, 287351, 287694, 288823, 308000, 301768, and 317267). Among the actions the licensee has performed, or plans to perform, to address this issue include: a complete extent-of-condition review of all through roof conduits that may be susceptible to water intrusion; drilling of weep holes in all susceptible junction boxes; repairs to damage caused by water intrusion; the sealing of the leaking conduit on Unit 1 Division 1 and Division 2 VY systems; and determining the actual cause of the water intrusion into the conduits. This issue is considered unresolved, pending the inspectors' receipt and review of the licensee's corrective action program products and the steps taken per the licensee's action plan to address the nonconforming condition. (URI 05000373/2005002-05)

1R20 Outage Activities (71111.20)

a. Inspection Scope

The inspectors evaluated outage activities for an refueling outage that began on February 7, 2005, and ended on March 16, 2005. The inspectors reviewed activities to ensure that the licensee considered risk in developing, planning, and implementing the outage schedule.

The inspectors observed or reviewed the reactor shutdown and cooldown, outage equipment configuration and risk management, electrical lineups, selected clearances, control and monitoring of decay heat removal, control of containment activities, startup and heatup activities, and identification and resolution of problems associated with the outage.

The inspectors' review of outage activities represented a single inspection sample.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors selected the following surveillance test activities for review. Activities were selected based upon risk significance and the potential risk impact from an unidentified deficiency or performance degradation that a system, structure, or component could impose on the unit if the condition were left unresolved. These reviews constituted nine inspection samples.

- Unit 1 and Unit 2 drywell leak detection systems tests and calibrations
- Unit 1 and Unit 2 standby liquid control tank concentration tests
- Unit 2 standby liquid control pump operability/inservice test
- Unit 2 emergency core cooling systems divisional response time testing
- Unit 2 main steam isolation valves local leak rate testing
- Unit 2 inboard and outboard feedwater check valve and outboard stop valve local leak rate testing
- Unit 2 residual heat removal shutdown cooling return pressure isolation valve leak rate test
- Unit 2 residual heat removal pressure isolation valve leak rate test
- Unit 2 standby liquid control explosive valve testing

The inspectors observed the performance of surveillance testing activities, including reviews for preconditioning, integration of testing activities, applicability of acceptance criteria, test equipment calibration and control, procedural use, control of temporary modifications or jumpers required for test performance, documentation of test data, Technical Specification applicability, impact of testing relative to performance indicator reporting, and evaluation of test data.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors selected the following temporary modifications for review. The inspectors reviewed the safety screening, design documents, UFSAR, and applicable Technical Specifications to determine that the temporary modifications were consistent with modification documents, drawings, and procedures. The inspectors also reviewed the post-installation test results to confirm that tests were satisfactory and that the actual impact of the temporary modification on the permanent system and interfacing systems were adequately verified.

- Installation of alternate method for determining Unit 1 drywell floor drain sump flow rate (TCCP 353167)
- Removal of 1DG032 internals and freeze seal (EC 353125)
- Energizing both 125 Vdc division 1 or 2 battery chargers simultaneously to support battery charger testing (EC 340584)
- Removal of station auxiliary transformer (SAT) metering (EC 353657)

These reviews constituted four inspection samples.

b. Findings

No findings of significance were identified.

1EP2 Alert and Notification System (ANS) Testing (71114.02)

a. Inspection Scope

The inspectors discussed with corporate and station-based Emergency Preparedness (EP) staffs the operation, maintenance, and periodic testing of the ANS in the LaSalle County Station's plume pathway Emergency Planning Zone (EPZ) to determine whether the ANS equipment was adequately maintained and tested in accordance with Emergency Plan commitments and procedures. The inspectors reviewed records of 2003 and 2004 preventive and non-scheduled maintenance activities, as well as January 2004 through December 2004 ANS operability test results.

These activities constituted a single inspection sample.

b. Findings

No findings of significance were identified.

1EP3 Emergency Response Organization (ERO) Augmentation Testing (71114.03)

a. Inspection Scope

The inspectors reviewed and discussed with station EP staff the procedures that included the primary and alternate methods of initiating an ERO activation to augment the on-watch ERO and the provisions for maintaining the station's ERO call-out roster. The inspectors reviewed critiques and a sample of corrective action program records of unannounced off-hours augmentation drills, which were conducted monthly between April 2004 and January 2005, to determine the adequacy of the critiques and associated corrective actions. The inspectors also reviewed the EP training records of a random sample of 30 LaSalle County Station ERO members, who were assigned to key and support positions, to determine whether they were currently trained for their assigned ERO positions. The inspectors also reviewed the LaSalle County Station's ERO roster to verify that appropriate personnel were assigned to each response position.

These activities constituted a single inspection sample.

b. Findings

No findings of significance were identified.

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies (71114.05)

a. Inspection Scope

The inspectors reviewed a sample of Nuclear Oversight staff's 2004 reviews of the LaSalle County Station's EP program to verify that these independent assessments met the requirements of 10 CFR 50.54(t). The inspectors also reviewed critique reports and samples of corrective action program records associated with those reviews. The inspectors also reviewed the licensee's critique of its emergency response to an actual seismic event, which included an Unusual Event declaration, that occurred in June 2004. The inspectors reviewed critique reports and samples of corrective action program records associated with the 2004 biennial exercise, as well as various EP drills conducted between July 2003 and December 2004, in order to verify that the licensee fulfilled its drill commitments and to evaluate the licensee's efforts to identify, track, and resolve concerns identified during these activities. The inspectors also reviewed samples of corrective action program documents associated with other aspects of the Station's EP program.

These activities constituted a single inspection sample.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

.1 Plant Walkdowns and Radiation Work Permit Reviews

a. Inspection Scope

The inspectors reviewed licensee controls and surveys in the following five radiologically significant work areas within radiation areas, high radiation areas, and airborne radioactivity areas in the plant and reviewed work packages which included associated licensee controls and surveys of these areas to determine if radiological controls including surveys, postings, and barricades were acceptable:

- Drywell control rod drive (CRD) pull/put activities;
- Reactor vessel disassembly and reassembly;
- Chemical decontamination and drywell work;
- Suppression pool diving;
- Low pressure heater bay maintenance.

This review represented one inspection sample.

The inspectors reviewed the radiation work permits (RWPs) and work packages used to access these five areas and other high radiation work areas to identify the work control instructions and control barriers that had been specified. Electronic dosimeter alarm set points for both integrated dose and dose rate were evaluated for conformity with survey indications and plant policy. Workers were interviewed to verify that they were aware of the actions required when their electronic dosimeters noticeably malfunctioned or alarmed.

This review represented one inspection sample.

The inspectors walked down and surveyed (using a calibrated NRC survey meter) these five areas to verify that the prescribed RWP, procedure, and engineering controls were in place, that licensee surveys and postings were complete and accurate, and that air samplers were properly located.

This review represented one inspection sample.

The inspectors reviewed RWPs for airborne radioactivity areas to verify barrier integrity and engineering controls performance (e.g., high efficiency particulate air (HEPA) ventilation system operation) and to determine if there was a potential for individual worker internal exposures of greater than 50 millirem committed effective dose equivalent. Work areas having a history of, or the potential for, airborne transuranics were evaluated to verify that the licensee had considered the potential for transuranic isotopes and provided appropriate worker protection. There were no airborne radioactivity work areas identified during the course of the inspection.

This review represented one inspection sample.

The adequacy of the licensee's internal dose assessment process for internal exposures greater than 50 millirem committed effective dose equivalent was assessed. There were no internal exposures greater than 50 millirem.

This review represented one inspection sample.

b. Findings

No findings of significance were identified.

.2 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed the licensee's self-assessments, audits, licensee event reports, and special reports related to the access control program to verify that identified problems were entered into the corrective action program for resolution.

This review represented one inspection sample.

The inspectors reviewed 15 corrective action reports related to access controls and 2 high radiation area radiological incidents when available (non-performance indicators identified by the licensee in high radiation areas <1R/hr). Staff members were interviewed and corrective action documents were reviewed to verify that follow-up activities were being conducted in an effective and timely manner commensurate with their importance to safety and risk based on the following:

- Initial problem identification, characterization, and tracking;
- Disposition of operability/reportability issues;
- Evaluation of safety significance/risk and priority for resolution;
- Identification of repetitive problems;
- Identification of contributing causes;
- Identification and implementation of effective corrective actions;
- Resolution of NCVs tracked in the corrective action system;
- Implementation/consideration of risk significant operational experience feedback.

This review represented one inspection sample.

The inspectors evaluated the licensee's process for problem identification, characterization, prioritization, and verified that problems were entered into the corrective action program and resolved. For repetitive deficiencies and/or significant individual deficiencies in problem identification and resolution, the inspectors verified that the licensee's self-assessment activities were capable of identifying and addressing these deficiencies.

This review represented one inspection sample.

The inspectors reviewed licensee documentation packages for all performance indicator (PI) events occurring since the PI events involved dose rates greater than 25 R/hr at 30 centimeters or greater than 500 R/hr at 1 meter. Barriers were evaluated for failure and to determine if there were any barriers left to prevent personnel access. There were no PI events occurring since the last inspection.

This review represented one inspection sample.

b. Findings

No findings of significance were identified.

.3 Job-In-Progress Reviews

a. Inspection Scope

The inspectors observed the following five jobs that were being performed in radiation areas, airborne radioactivity areas, or high radiation areas for observation of work activities that presented the greatest radiological risk to workers:

- Drywell CRD pull/put activities;
- Reactor vessel disassembly and reassembly;

- Chemical decontamination and drywell work;
- Suppression pool diving;
- Low pressure heater bay maintenance.

The inspectors reviewed radiological job requirements for these five activities, including RWP requirements and work procedure requirements, and attended As-Low-As-Is-Reasonably-Achievable (ALARA) job briefings.

This review represented one inspection sample.

The above review is combined with NRC IP 71121.02, “ALARA, Planning, and Controls,” and documented in Section 2OS2.2.

Job performance was observed with respect to these requirements to verify that radiological conditions in the work area were adequately communicated to workers through pre-job briefings and postings. The inspectors also verified the adequacy of radiological controls including required radiation, contamination, and airborne surveys for system breaches; radiation protection job coverage which included audio and visual surveillance for remote job coverage; and contamination controls.

This review represented one inspection sample.

Radiological work in high radiation work areas having significant dose rate gradients was reviewed to evaluate the application of dosimetry to effectively monitor exposure to personnel and to verify that licensee controls were adequate. These work areas involved areas where the dose rate gradients were severe (diving activities and the reactor water cleanup (RWCU) heat exchanger room) which increased the necessity of providing multiple dosimeters and/or enhanced job controls.

This review represented one inspection sample.

b. Findings

No findings of significance were identified.

.4 Radiation Worker Performance

a. Inspection Scope

During job performance observations, the inspectors evaluated radiation worker performance with respect to stated radiation protection work requirements and evaluated whether workers were aware of the significant radiological conditions in their workplace, of the RWP controls and limits in place, and that their performance had accounted for the level of radiological hazards present.

This review represented one inspection sample.

The inspectors reviewed radiological problem reports which found that the cause of the event was due to radiation worker errors to determine if there was an observable pattern traceable to a similar cause, and to determine if this perspective matched the corrective action approach taken by the licensee to resolve the reported problems. These problems, along with planned and taken corrective actions were discussed with the Radiation Protection Manager.

This review represented one inspection sample.

b. Findings

(1) Electrician Enters the Drywell on the Wrong RWP

Introduction

A self-revealing finding of very low safety significance (Green) and an associated NCV were identified when an electrician logged onto a general all-buildings minor maintenance activities RWP and entered the drywell, a posted HRA, contrary to the licensee's Technical Specifications. The finding was identified when the electrician's electronic dosimeter alarmed after he entered a 106 millirem/hour dose field in the drywell.

Description

On February 7, 2005, an electrician was assigned to minor electrical maintenance work in the drywell.

The workers proceeded to the RP desk to sign on to the RWP 10003998, "Unit 2 Drywell (construction) Minor Maintenance Activities for L2R10." This RWP contained proper controls for the assigned activity in a HRA. The workers proceeded to the electronic dosimeter (ED) station where the electrician mistakenly signed onto RWP 10003938, "All-Building Minor Maintenance Activities." The ED computer sign-in had displayed screens to allow the individual to verify the RWP number, and these screens were incorrectly answered in the affirmative. The electrician knew the dose and dose rate limits for the correct RWP from the HRA pre-job brief. The electrician entered the radiologically controlled area (RCA) and proceeded to the work area at approximately 1:50 a.m. and left the RCA at 5:00 p.m.

When the electrician exited the drywell and checked out of the RCA, he received a warning on the computer screen that he had received a dose rate alarm during the entry. He immediately notified RP staff of the warning. The RP staff investigated the event and identified that he had signed on to the wrong RWP.

The individual received a total dose of 4 millirem, and the maximum dose rate measured by the ED was 106 millirem/hour.

The failure to assure through self-checking that each high radiation area entry is made using the correct RWP that includes specification of radiation dose rates in the immediate work area and other appropriate radiation protection equipment and measures is contrary to Technical Specification 5.7.1: (a) requiring entry controls; and (b) requiring that an appropriate RWP be utilized by workers.

The licensee's initial prompt investigation determined the cause to be a failure of human performance error prevention techniques. Specifically, the electrician lacked self-checking and peer-checking in entering the wrong RWP and accepting the ED log-in screens that asked if this was the correct RWP. As immediate corrective actions, the individual was locked out of the stations RCA, and the licensee initiated an investigation. Additionally, all site personnel were notified of this event through a station safety alert.

Analysis

The inspectors determined that the performance deficiency associated with this event was failure to follow procedure, in that the individual did not electronically sign onto the right RWP. The finding, under the Occupational Radiation Safety Cornerstone, does not involve the application of traditional enforcement because it did not result in actual safety consequences or potential to impact the NRC's regulatory function and was not the result of any willful actions. The finding was more than minor as it could be reasonably viewed as a precursor to a more significant event. The finding is associated with one of the cornerstone attributes, specifically occupational radiation safety.

The inspectors determined that the finding was more than minor because the occurrence involved an individual worker potential unplanned, unintended dose resulting from actions or conditions contrary to licensee procedures and radiation work permit which could have been significantly greater as a result of a single minor, reasonable alteration of the circumstances. The finding was evaluated using the Significance Determination Process (SDP) for the Occupational Radiation Safety Cornerstone and was determined to be of very low safety significance (Green). The finding did not involve an ALARA issue, as collective dose was not an issue. Furthermore, the individual's radiation exposure was low relative to regulatory limits; there was not a substantial potential for a worker overexposure; and the licensee's ability to assess worker dose was not compromised.

Because the inspectors determined that the primary cause for the finding was related to the cross-cutting aspect of human performance, it is discussed in Section 4OA4 as well.

Enforcement

Technical Specification 5.7.1(a) and 5.7.1(b) require for HRAs, with dose rates not exceeding 1.0 rem per hour at 30 centimeters from the radiation source, that access to and activities in each area shall be controlled by means of a RWP that includes the specification of radiation dose rates in the immediate work area and other appropriate radiation protection equipment and measures. Contrary to the above, on February 7, 2005, an electrician received a dose rate alarm when working in the drywell during the L2R10 refueling outage. The worker entered an elevated dose rate area above the floor, an area that was not normally surveyed, and this action was contrary to the limits of the RWP onto which he had electronically acknowledged. Because entry into the RCA was conducted under an all-buildings scaffold activities RWP, the entry into the HRA was monitored by EDs. Since the finding is of very low safety significance and had been entered into the corrective action system as IR 218052, the associated violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000374/2005002-06).

(2) Venture Pipefitters Enter HRA Without RWP Brief on February 13, 2005

No findings of significance were identified. One unresolved item (URI) was identified.

On February 13, 2005, a Radiation Protection Technician (RPT) identified that a pipefitter foreman and two pipefitters had inappropriately gone past two HRA postings and barricades to enter the condenser pit room. Prior to the unauthorized entry, the pipefitters discussed their work and RWP limitations (RWP 1004122, "Unit 2 Minor Maintenance-Non-HRA") with RPTs at the low pressure heater bay access point. The RPTs thought the pipefitters were working in the adjacent amertap room, which was not a posted HRA. The RPTs and pipefitters confirmed through a 3-way communication that the discussion was not an HRA brief and that they were not to enter any HRAs. In addition, all three pipefitters had attended the required radworker training that specifically challenged the workers on HRA entry requirements.

When the pipefitters entered the condenser pit room HRA to access their assigned work area, they identified that they needed a survey completed before accessing a scaffold. They requested assistance from a RPT in the area for this task. The RPT asked if they had received an HRA brief. They told the RPT they had received the required brief. The RPT completed the survey for them, and the pipefitters completed the assigned work in the HRA and left the area. The highest dose rate for the pipefitters was 38 millirem/hour and the highest dose was 3.7 millirem. No electronic dosimeter alarms were activated by the entry.

When the RPT returned to the low pressure heater bay access point he questioned why he was not made aware that the pipefitters were being sent to the condenser pit for assigned work. At this point, it was identified that the pipefitters were not properly briefed and were on the wrong RWP.

Because the pipefitters had potentially been directed by their supervisor to enter the HRA, the event remains under review by the NRC pending further investigation and is categorized as an Unresolved Item. (URI 05000374/2005002-07)

.5 Radiation Protection Technician Proficiency

a. Inspection Scope

During job performance observations, the inspectors evaluated RPT performance with respect to radiation protection work requirements and evaluated whether they were aware of the radiological conditions in their workplace, the RWP controls and limits in place, and if their performance was consistent with their training and qualifications with respect to the radiological hazards and work activities.

This review represented one inspection sample.

The inspectors reviewed radiological problem reports which found that the cause of the event was radiation protection technician error to determine if there was an observable pattern traceable to a similar cause and to determine if this perspective matched the corrective action approach taken by the licensee to resolve the reported problems.

This review represented one inspection sample.

b. Findings

No findings of significance were identified.

2OS2 As Low As Is Reasonably Achievable Planning And Controls (ALARA) (71121.02)

.1 Radiological Work Planning

a. Inspection Scope

The inspectors evaluated the licensee's list of work activities ranked by estimated exposure that were in progress and reviewed the following five work activities of highest exposure significance:

- Drywell CRD pull/put activities;
- Reactor vessel disassembly and reassembly;
- Chemical decontamination and drywell work;
- Suppression pool diving;
- Low pressure heater bay maintenance.

This review represented one inspection sample.

For these five activities, the inspectors reviewed the ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements in order to verify that the licensee had established procedures, and engineering and work controls that were based on sound radiation protection principles in order to achieve occupational exposures that were ALARA. This also involved determining that the licensee had reasonably grouped the radiological work into work activities, based on historical precedence, industry norms, and/or special circumstances.

This review represented one inspection sample.

The inspectors compared the results achieved including dose rate reductions and person-rem used with the intended dose established in the licensee's ALARA planning for these five work activities. Reasons for inconsistencies between intended and actual work activity doses were reviewed.

This review represented one inspection sample.

b. Findings

No findings of significance were identified.

.2 Job Site Inspections and ALARA Control

a. Inspection Scope

The inspectors observed the following five jobs that were being performed in radiation areas, airborne radioactivity areas, or high radiation areas for observation of work activities that presented the greatest radiological risk to workers:

- Drywell CRD pull/put activities;
- Reactor vessel disassembly and reassembly;
- Chemical decontamination and drywell work;
- Suppression pool diving;
- Low pressure heater bay maintenance.

The licensee's use of ALARA controls for these work activities was evaluated. Specifically, the licensee's use of engineering controls to achieve dose reductions was evaluated to verify that procedures and controls were consistent with the licensee's ALARA reviews, that sufficient shielding of radiation sources was provided for, and that the dose expended to install/remove the shielding did not exceed the dose reduction benefits afforded by the shielding.

This review represented one inspection sample.

b. Findings

No findings of significance were identified.

.3 Source-Term Reduction and Control

a. Inspection Scope

The inspectors reviewed licensee records to determine the historical trends and current status of tracked plant source terms and to evaluate if the licensee was making allowances and had developed contingency plans for expected changes in the source term due to changes in plant fuel performance issues or changes in plant primary chemistry. Additionally, the inspectors reviewed the licensee's chemical decontamination activities and cold noble metals addition during this refueling outage.

This review represented one inspection sample.

b. Findings

No findings of significance were identified.

.4 Radiation Worker Performance

a. Inspection Scope

Radiation worker and RPT performance was observed during work activities being performed in radiation areas, airborne radioactivity areas, and high radiation areas that presented the greatest radiological risk to workers. The inspectors evaluated whether workers demonstrated the ALARA philosophy in practice by being familiar with the work activity scope and tools to be used, by utilizing ALARA low dose waiting areas and that work activity controls were being complied with. Also, radiation worker training and skill levels were reviewed to determine if they were sufficient relative to the radiological hazards and the work involved.

This review represented one inspection sample.

b. Findings

No findings of significance were identified.

.5 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed the licensee's self-assessments, audits, and special reports related to the ALARA program since the last inspection to determine if the licensee's overall audit program's scope and frequency for all applicable areas under the Occupational Cornerstone met the requirements of 10 CFR 20.1101(c).

This review represented one inspection sample.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

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

.1 Emergency Preparedness Performance Indicator Verification

a. Inspection Scope

The inspectors reviewed the licensee's records associated with the three EP performance indicators (PIs) listed below. The inspectors verified that the licensee accurately reported these indicators in accordance with relevant procedures and Nuclear Energy Institute guidance endorsed by NRC. Specifically, the inspectors reviewed licensee records associated with PI data reported to the NRC for the period January 2004 through December 2004. Reviewed records included: procedural guidance on assessing opportunities for the three PIs; assessments of PI opportunities during pre-designated control room simulator training sessions, the 2004 biennial exercise, and “mini-drills”; revisions of the roster of personnel assigned to key ERO positions; and results of periodic alert and notification system (ANS) operability tests. The following PIs were reviewed:

Station Common

- ANS
- ERO Drill Participation
- Drill and Exercise Performance

These reviews represented three inspection samples.

b. Findings

No findings of significance were identified.

.2 Data Submission Issue

a. Inspection Scope

The inspectors performed a review of the data submitted by the licensee for the 4th Quarter 2004 performance indicators for any obvious inconsistencies prior to its public release in accordance with IMC 0608, “Performance Indicator Program.”

This review did not represent an independent inspection sample.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

Cornerstones: Initiating Events and Mitigating Systems

.1 Routine Review of Identification and Resolution of Problems

a. Inspection Scope

As a part of the various inspection procedures used to accomplish Sections 1 and 2 of this report, the inspectors verified that problems and issues associated with inspection samples were entered into the licensee’s corrective action program (CAP). Additionally, the inspectors verified that the licensee identified issues at an appropriate threshold and that problems were properly addressed for resolution. CAP attributes reviewed included: complete and accurate identification of the problem; that the timeliness of problem review was commensurate with safety; that evaluation and disposition of performance issues, generic implications, common causes, contributing factors, root causes, extent of condition reviews, and previous occurrences reviews were proper and adequate; and that classification and prioritization of corrective actions were commensurate with safety and sufficient to prevent recurrence of the issue.

These routine reviews concerning the identification and resolution of problems were an integral part of the inspection samples documented elsewhere in this report. As such, they did not represent any additional inspection samples.

b. Findings

Introduction

A finding of very low safety significance (Green) was identified by the inspectors during review of the circumstances associated with a small fire in the 2B RHR corner room on February 16, 2005, (Section 1R05.2). The inspectors determined that the licensee had, during several opportunities, failed to take timely and effective corrective actions with respect to ignition control for hot work. An associated Non-Cited Violation (NCV) of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action,” was also identified.

Description

On February 16, 2005, at approximately 2:30 p.m., work was in progress in the 2B RHR corner room to demolish a section of pipe that was slated for removal as part of an approved permanent plant modification. The work involved cutting a vertical run of 20-inch diameter pipe into sections approximately 1 foot in length to facilitate ease of removal. A single fire watch was assigned to observe in progress hot work activities. Fire blanketing was placed in the area of the hot work, with additional material surrounding the floor piping penetration to prevent sparks from falling through the penetration. A fire blanket extended outward for approximately 8 feet from the hot work area. During the course of the hot work activities, some of the sparks generated by the cutting were thrown past the area covered by the fire blanket. These sparks fell through open floor grating to the 694' elevation below.

At some point following lunch, cleaning material was staged on the 694' elevation below the area where the hot work was in progress. When interviewed as part of the licensee’s ACE, the fire watch stated that he was not aware of the introduction of this combustible material to this area. Sparks that fell from the hot work above ignited a small Class ‘A’ fire in this material. A laborer in the area detected the fire and attempted to extinguish it by stepping on the flames. When this action was not successful, a mop was used in an attempt to smother the flames. When this action, too, proved ineffective, the laborer notified the fire watch on the level above, who was able to extinguish the fire with a dry chemical fire extinguisher. The control room was notified by personnel involved in the 2B RHR corner room fire.

On February 15, 2005, the day before the fire, a region-based NRC inspector touring the Unit 2 feedwater heater bay identified deficiencies relating to ignition control at no less than four work locations where hot work was in progress. In each case, the inspector observed sparks from in progress hot work activities thrown out beyond the established fire blanket protection areas. The inspector estimated that the fire blanket coverage, at each site he observed, extended out only 6 to 8 feet from the work location. This level of coverage was well short of the 35 feet required by plant procedures governing hot work ignition control. Consequently, each hot fire activity observed by the inspector had hot sparks passing through deck grating and falling to the levels below where the actual work was taking place. The inspector discussed his observations with the personnel conducting the work and their assigned fire watches at each job site, however, because the personnel did not seem to be responsive, in his opinion, to his comments, the inspector also discussed the observations with a duty radiation protection (RP) technician in the heater bay and the on-duty outage Heater Bay Coordinator.

Following the fire in the 2B RHR corner room on February 16, 2005, inspectors reviewed the licensee's actions in response to the NRC observations regarding hot work ignition controls in the Unit 2 heater bay that had occurred on the preceding day. In discussions with senior licensee managers, the inspectors identified that communication of the NRC observations from the Unit 2 heater bay on February 15, 2005, had not gone beyond the Heater Bay Coordinator, nor had the licensee generated an Issue Report (IR) to enter the observations as required by their corrective action program (CAP).

On February 22, 2005, six days following the 2B RHR corner room fire, the NRC Resident Inspector and a region-based inspector were conducting a routine plant tour that included the 2B RHR corner room. The inspectors were surprised to find that their passage through the lower levels of the 2B RHR corner room and up the stairs was blocked by a shower of sparks from hot work in progress from above. When personnel conducting the hot work noticed the NRC inspectors, they ceased grinding operations and allowed the inspectors to climb the stairs and exit the 2B RHR corner room. This hot work activity was for the same modification project that had caused the fire six days earlier.

The inspectors immediately brought their observations to the attention of licensee management personnel in the Outage Control Center. The licensee ordered work in the 2B RHR corner room stopped and conducted a follow-up inspection of the work location. Licensee managers determined that some of the fire blanket material added to the 2B RHR corner room job site following the fire had been removed as a part of planned housekeeping and demobilization efforts. However, three fire watches were present in the 2B RHR corner room during the hot work and the potential for another fire was small. The licensee generated IR 304516 to document their actions and the inspectors' observations.

<u>Analysis</u>

In reviewing the 2B RHR corner room fire, the inspectors evaluated the licensee corrective actions for NRC observations concerning hot work ignition control passed to licensee personnel both before and after the February 16, 2005 fire. Given the lack of effective communication of this issue within the licensee's organization, and the fact that an IR had not been written for the issues discussed with the licensee on February 15, the inspectors determined that there was a performance deficiency associated with the corrective actions taken by the licensee. Specifically, the licencee's response to inspector observations regarding hot work ignition controls in the Unit 2 heater bay on

February 15, 2005, was narrowly focused and not properly documented or communicated within the licensee's organization, resulting in the potential for adverse consequences to plant equipment and personnel in the vicinity of hot work. The inspectors concluded that had the licensee's corrective action response to the February 15, 2005, observations been more thorough and robust, it is conceivable that the 2B RHR corner room fire may not have occurred the following day. Similarly, the inspectors' observations in the 2B RHR corner room six days after the fire indicated that the licensee's corrective actions for the actual event were largely ineffective, as the same deficient conditions in fire blanket coverage that had permitted the fire to occur in the first place continued to exist.

The objective of the Initiating Events Cornerstone of Reactor Safety is "to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations." In accordance with NRC Inspection Manual Chapter (IMC) 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," the inspectors determined that the finding was of more than minor significance in that it had a direct impact on this cornerstone objective. Specifically, one of the key attributes associated with this cornerstone objective is protection against fires, and the inspectors determined that the licensee's failure to take timely and effective corrective actions with respect to hot work ignition control deficiencies constituted a clear threat to fire prevention at the facility.

The inspectors determined that the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," and conducted a Phase 1 initial screening. Because the finding was associated with fire protection, this was accomplished using IMC 0609, Appendix F, Attachment 1, "Fire Protection SDP Phase 1 Worksheet." As discussed in Section 1R05.2, the inspectors determined that the finding was associated with the licensee's ability to reach and maintain cold shutdown conditions. As a result of the phase 1 screening, this finding was determined to be of very low safety significance (Green) and within the licensee's response band.

Enforcement

Criterion XVI of 10 CFR 50, Appendix B, states, in part, that: "Measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected." Contrary to this requirement, the licensee failed to take adequate corrective actions for procedural noncompliances relating to hot work ignition controls in the 2B RHR corner room. Specifically, on February 16, 2005, a fire occurred in the 2B RHR corner room caused, in part, by procedural noncompliances related to hot work ignition control. On February 22, 2005, the inspectors identified that some of the same hot work ignition control procedural noncompliances were still present in the 2B RHR corner room that could have adversely impacted plant equipment or personnel.

Following various discussions with the inspectors on this issue, the licensee entered the issue into their CAP as issue report (IR) 319064. This IR calls for a comprehensive common cause analysis (CCA) by the licensee, which will examine the various fire protection issues identified to determine whether or not a generic fire protection

programmatic weakness is present. Because the licensee has entered the issue into their corrective action program and the finding is of very low safety significance (Green), this violation of 10 CFR 50, Appendix B, Criterion XVI, is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy.
(NCV 05000374/2005002-08)

.2 Selected Issue Follow-up Inspection: Corrective Actions for Emergency Diesel Generator (EDG) Reverse Power Trips

Introduction

The inspectors selected the licensee’s actions in response to recurring reverse power trips of the station’s EDGs for a more in-depth review. Since 1989, the licensee has recorded 25 reverse power trips of EDGs at the station. The focus of this inspection was a review of the licensee’s root cause report (RCR) for a reverse power trip of the 2A EDG that occurred on December 7, 2004, which was the most recent event.

The inspectors’ review of this issue constituted a single inspection sample.

a. Effectiveness of Problem Identification

(1) Inspection Scope

The inspectors reviewed RCR 280218, “Reverse Power Trip of the 2A Diesel Generator,” to verify that the licensee's identification of the problems were complete, accurate, and timely, and that the consideration of extent-of-condition review, generic implications, common cause, and previous occurrences were adequate.

(2) Issues

As discussed in Section (b) that follows, the licensee’s ability to identify the underlying cause for this ongoing issue has, in general, not been the reason that the issue has been drawn out for such a long period of time. The licensee’s investigations following both the June 2, 1999, reverse power trip of the 1B EDG and the February 9, 2000, reverse power trip of the 2B EDG both readily identified problems associated with the procedural requirement plant operators faced to drive EDG load down to less than 200 kW before opening the EDG output breaker. The actions of evaluating the issue and ensuring that the corrective actions taken were effective are where the licensee’s corrective action processes fell short.

b. Prioritization and Evaluation of Issues

(1) Inspection Scope

In reviewing RCR 280218, “Reverse Power Trip of the 2A Diesel Generator,” the inspectors considered the licensee’s evaluation and disposition of performance issues, evaluation and disposition of operability issues, and application of risk insights for prioritization of issues.

(2) Findings

Introduction

A finding of very low safety significance (Green) was identified by the inspectors. The inspectors determined that the licensee had failed during prior opportunities to fully evaluate the nature of the problem leading to various EDG reverse power trips. The most recent of these events were a reverse power trip of the 2B EDG on August 18, 2004, for which no root cause was ever determined, and a reverse power trip of the 2A EDG that occurred on December 7, 2004, which was the topic of the licensee's root cause report (RCR). An associated Non-Cited Violation (NCV) of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," was also identified by the inspectors.

Description

On December 7, 2004, plant operators were performing a shutdown of the 2A EDG in accordance with approved procedures. As part of this activity, the control room crew was reducing 2A EDG load in preparation for opening the 2A EDG output breaker. Per the procedure, load on the 2A EDG was reduced to approximately 200 kilowatts (kW) and approximately 200 kilovolts-amperes-reactive (kVAR).

Just before the next step in the procedure, operators noted a caution statement that identified the fact that the EDG can become unstable and trip on reverse power if allowed to go below 200 kVAR for more than 1.5 seconds. The control room crew was aware of this caution and discussed the next actions for reducing load below 200 kW/200 kVAR and then opening the EDG output breaker. While performing this next step, the control room crew received a 2A EDG Trouble Alarm. Operators in the field reported local alarms for EDG undervoltage, reverse power, and an EDG lockout.

As a part of the RCR, the licensee conducted interviews with the operators that shutdown the 2A EDG. These interviews revealed that the plant operators took approximately 3 seconds to complete the opening of the EDG output breaker actions, versus the procedurally stated caution that called for less than 1.5 seconds. The license concluded that the requirement for the operators to act in a mere 1.5 seconds constituted a human performance challenge.

Since 1989, there have been 25 recorded reverse power trips of EDGs at LaSalle Station. Among the more notable events reviewed by the inspectors were:

- On June 2, 1999, the 1B EDG tripped on reverse power. An apparent cause evaluation (ACE) was performed for this event and identified that at low load (less than 200 kW), the EDG is in an inherently unstable position relative to the grid. However, there were no corrective actions associated with this investigation. The ACE was closed based on a statement by personnel that proper guidance existed in the EDG operating procedure and that no additional action was required.

- On February 9, 2000, the 2B EDG tripped on reverse power. An investigation identified the root cause as an operator skill-based human performance error in the untimely opening of the output breaker. The operator's actions to reduce load, then perform a self-check, then request a peer-check, all prior to opening the EDG output breaker were determined to require too much time. The reverse power trip occurred as a result. However, based on the evaluations of the licensee's engineering staff, the 200 kW/200 kVAR caution limits in the EDG procedures were considered appropriate and no procedural revisions took place.

- On August 18, 2004, the 2B EDG tripped on reverse power. The licensee's investigation focused almost primarily on the equipment failures subsequent to the reverse power trip. The investigation plan did, however, call for a review of the previous root cause for 2B EDG trip in 2000, and an assessment of the adequacy of the corrective actions. In addition, a review of procedural and human performance aspects of the EDG shutdown process were also required. Despite this, however, there was no root cause identified associated with the reverse power trip on August 18, and no corrective actions to specifically prevent recurrence were instituted.

Analysis

In reviewing the EDG reverse power trips at the station leading up to the most recent reverse power trip of the 2A EDG on December 7, 2004, the inspectors determined that there was a performance deficiency associated with the corrective actions taken by the licensee. Specifically, in response to the prior events, one as recently as August 18, 2004, the licensee's evaluation of the issue failed to generate any corrective actions to address the inherently unstable position into which plant operators were being placed by the procedural requirement to drive EDG load down below 200 kW before opening the EDG output breaker. In one case as discussed above, in 1999, the licensee's evaluation actually did determine the cause of the reverse power trips to be due to this procedural requirement and the naturally unstable position created by it. However, no corrective actions were taken. While following the August 18, 2004, reverse power trip of the 2B EDG actions were created to evaluate potentially changing the EDG operating procedures to provide less limitations on tripping the output breaker, these evaluations were not given a high enough priority for them to have been completed by the time the December 7, 2004, reverse power trip occurred. Subsequently, only after the 2A EDG reverse power trip on December 7, 2004, were the evaluations completed in rapid order and procedure changes enacted.

The objective of the Mitigating Systems Cornerstone of Reactor Safety is "to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage)." In accordance with NRC Inspection Manual Chapter (IMC) 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," the inspectors determined that the finding was of more than minor significance in that it had a direct impact on this cornerstone objective. Specifically, the inspectors concluded that the licensee's performance deficiency was responsible for the reverse power trip of the 2A EDG on December 7, 2004, which caused the EDG to be unavailable for an additional 26 hours.

The inspectors determined that the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," and conducted a Phase 1 characterization and initial screening. Because the finding involved the loss of only one train of safety related equipment and the loss was for less than the Technical Specification allowed outage time, the inspectors determined it to be of very low safety significance (Green) and within the licensee's response band.

Enforcement

Criterion XVI of 10 CFR 50, Appendix B, states, in part, that: "Measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected." Contrary to this requirement, the licensee failed to promptly identify and correct procedural deficiencies associated with the unloading and securing of the station's EDGs. These procedural deficiencies contributed to or directly caused 25 EDG reverse power trips since 1989. Following a subsequent reverse power trip of the 2A EDG on December 7, 2004, the licensee entered the issue into their CAP as IR 280218. This issue report led to a RCR, with the following corrective actions planned or completed: establishment of a less restrictive EDG load limit to allow opening the EDG output breaker when load is less than approximately 500 kW; additional training for licensed operators in the areas of EDG theory and operation and the effects of reverse power conditions on diesel generators; and revision of simulator modeling for EDGs to more accurately reflect actual plant performance for reverse power trips. Because the licensee has entered the issue into their corrective action program and the finding is of very low safety significance, this violation of 10 CFR 50, Appendix B, Criterion XVI, is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy. (NCV 05000374/2005002-09)

c. Effectiveness of Corrective Actions

(1) Inspection Scope

The inspectors reviewed multiple related CAP documents relating to the 25 EDG reverse power trips on record since 1989 at the station. The intent of this review was to determine if the CAP actions addressed generic implications, and to verify that corrective actions were appropriately focused to correct the problem.

(2) Issues

The inspectors determined that the licensee's corrective actions for EDG reverse power events, that actually produced corrective actions, had only marginal impact in reducing the number and frequency of the EDG reverse power trip occurrences. However, as discussed in the section above, there were EDG reverse power trip events that did not generate any corrective actions. For the actions taken in the aftermath of the reverse power trip of the 2B EDG on August 18, 2004, the inspectors concluded that the licensee's planned actions had a good probability for success, but were not prioritized for completion in time to prevent the subsequent December 7, 2004, reverse power trip of the 2A EDG. These corrective actions included a Corporate Engineering review of the reverse power trip settings for all LaSalle EDGs to determine if there was additional margin in the setpoints, and a review to determine if the unloading sequence could be changed to permit opening the EDG output breaker at higher loads.

4OA3 Event Follow-up (71153)

Cornerstones: Initiating Events and Mitigating Systems

.1 Single Failure Vulnerability of Safety Related 4,160 Vac Division 1 and Division 2 Protective Relay Circuitry (ENS 41366)

a. Inspection Scope

On January 27, 2005, Crystal River Unit 3 (CR-3) discovered a single failure that could prevent both EDGs and both offsite power sources from supplying power to their respective engineered safeguards (ES) buses. This was a condition reportable under 10 CFR 50.72 (b)(3)(ii)(B), for a plant being in an unanalyzed condition that significantly degraded plant safety (ENS 41362).

Just prior to lunch on February 1, 2005, the LaSalle Station Electrical System Engineering Supervisor was informed of the CR-3 event and provided a copy of ENS 41362 by the LaSalle Station NRC Senior Resident Inspector. LaSalle Station engineers reviewed the safety related bus protective relaying circuitry to determine if a similar vulnerability existed. In the late afternoon of the following day, plant engineers determined that a single failure vulnerability existed for LaSalle between the current transformer (CT) circuits of the divisional safety related buses (e.g., 141Y to 142Y, 241Y to 242Y).

Upon notification of the discovery and subsequent entry into a 12-hour Technical Specification Required Action potentially leading to the shutdown of both LaSalle units, inspectors responded to the plant to monitor the licensee’s actions. The inspectors observed plant parameters and status; evaluated the performance of plant 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 as intended, and that no human performance errors complicated the event response.

The inspectors’ response to and review of this event constituted a single inspection sample.

b. Findings

No findings of significance were identified. One URI was identified.

At approximately 3:42 p.m. on February 2, 2005, plant operators entered a 12-hour Technical Specification Required Action for unavailability of offsite and onsite power systems. A licensee analysis of the issue determined that the CT circuits that supply the overcurrent relay scheme for each divisional bus were connected to a common point that supplies control room indication for the total station auxiliary transformer (SAT) ‘Y’ winding power (kW) and current (amperes). Further, licensee engineers determined that an open circuit condition on any of the CT phases downstream of the common point in the circuit would have resulted in an unbalanced current condition, which would have initiated a trip of the associated SAT feed breakers for the applicable buses (e.g., 141Y and 142Y, 241Y and 242Y). Specifically, the current unbalance would have actuated the ground fault relays, causing the SAT feed breaker relays to lock out both divisions. Following a trip of the bus feed breakers, the lockout relay for the respective bus would have initiated a trip of the other bus breakers and prevented any closure of these breakers. The ultimate result would have been a loss of all onsite and offsite power sources to both 4160 Vac Division 1 and Division 2 safety related buses, because no EDG or offsite power source would have been permitted to close onto the respective Division 1 or Division 2 safety buses.

A temporary modification was developed and installed on each unit to isolate the common metering circuitry between the Division 1 and Division 2 buses responsible for the single point vulnerability. These modifications were installed and Technical Specification Required Actions exited on Unit 1 in 7 hours, 23 minutes, and on Unit 2 in 6 hours, 48 minutes. All actions were monitored by the inspectors. The licensee entered the issue into their corrective action program as IR 297076, and into their corporate corrective action program as IR 299641.

The issue is presently considered unresolved pending a more detailed NRC review of the licensee's root cause report and LER for this issue. (URI 05000373/2005002-10; 05000374/2005002-10)

.2 Inadvertent Reactor Recirculation Flow Increase Results in Unit 1 Reactor Power Excursion to 103.17 Percent

a. Inspection Scope

On February 23, 2005, the inspectors responded to the control room following notification from the licensee that the Unit 1 licensed reactor power limit of 3489 megawatts thermal (MWth) had been exceeded by approximately 3.17 percent for several minutes following an unplanned and unexpected increase in reactor recirculation flow. The inspectors observed plant parameters and status; evaluated the performance of plant systems and licensee actions; and confirmed that the licensee properly reported the event as required by Section 2.F(a) of Facility Operating License No. NPF-11. The inspectors further determined that no nuclear fuel thermal limits were violated, and that the event was bounded by the events discussed in the UFSAR.

The inspectors' response to and review of this event constituted a single inspection sample.

b. Findings

No findings of significance were identified. One URI was identified.

On February 23, 2005, at approximately 11:41 a.m., Unit 1 exceeded License Condition 2.C (1), which limits the maximum thermal power of the unit to 3489 MWth. Unit 1 reached a peak transient power of approximately 3599.5 MWth, or 103.17 percent of the licensed limit, for about 8 minutes.

At approximately 11:46 a.m., the Unit 1 control room supervisor (CRS), a licensed senior reactor operator (SRO) observed that Unit 1 power had increased from 1194 megawatts electric (MWe) to 1223 MWe, and directed the on-watch nuclear station operator (NSO), a licensed reactor operator (RO) to lower power to 95 percent. From approximately 11:47 a.m. to 11:48 a.m., the NSO attempted to reduce reactor power using the "LOWER" pushbutton on the reactor recirculation (RR) ganged (i.e., master) flow control station. After two attempts to lower power using the RR ganged flow control station, the NSO did not believe that power was responding as it should have, and he placed the RR flow controllers for each RR loop's flow control valve (FCV) into manual and closed them both to approximately 80 percent at 11:49 a.m. The FCVs responded, and reactor power was reduced to about 3471 MWth, or approximately 99.5 percent. Plant power was subsequently stabilized at about 95 percent while the licensee began an investigation of the event.

At approximately 5:34 p.m., the licensee contacted the NRC Region III Director of Reactor Projects via telephone, in accordance with the reporting conditions of Section 2.F(a) of the Unit 1 license, to discuss the event. A follow on written report was sent on March 9, 2005.

At the time of this writing, the event is still under investigation by the licensee. FCVs on both LaSalle units (4 valves total) were being maintained in manual control pending the outcome of the investigation. Initial troubleshooting of the RR ganged flow controller had not revealed any abnormalities; however, further diagnostic testing at an off site lab was planned. The licensee's investigation into potential equipment problems associated with the RR flow controllers was entered into their CAP as IR 304613. This investigation was scheduled for completion in April 2005.

While the event did not trigger any control board annunciator alarms (none should have been triggered based on a review of the event by the inspectors), the licensee investigated the on-watch crew's apparent lack of response to several low-level plant process computer alarms that were actuated on increasing plant pressure and power. This root cause investigation was being conducted within the licensee's CAP under IR 305612, and was expected to be completed in April 2005.

In addition to maintaining FCVs in manual control, corrective actions taken by the licensee at this point also included changing several plant process computer alarms from low-level alarms, which annunciate only briefly and then are automatically silenced, to higher level alarms that require operator action to silence the alarm tones. Computer alarms included in this change were MWth, MWe, and reactor pressure.

This issue is considered unresolved pending the inspectors' receipt and review of the licensee's CAP investigations regarding any potential equipment malfunctions of the RR flow control system, and the root cause investigation into the event (URI 05000373/2005002-11)

4OA4 Cross-Cutting Aspects of Findings

Cornerstones: Initiating Events, Barrier Integrity and Occupational Radiation Safety

Human Performance

Several of the findings and one of the licensee-identified violations described elsewhere in this report had human performance deficiencies as their major causal elements.

- A Green finding and associated NCV described in Section 1R05.2 involved the failure of plant personnel conducting hot work to follow procedural requirements for fire blanket protection in the vicinity of the work site. The improper fire blanket coverage and lack of attentiveness on the part of the assigned fire watch and other licensee personnel responsible for ensuring that ignition controls in the vicinity of hot work were being properly applied resulted in a small Class 'A' fire in the 2B RHR corner room.

- A Green finding and associated NCV described in Section 1R13.2 involved the failure of maintenance planners and maintenance first line supervisors to have properly identified the risk associated with an electrical meter replacement for the 1A circulating water (CW) pump. The improper assessment of risk, in combination with an inadvertent electrical short caused during the meter replacement itself, resulted in a trip of the 1C CW pump, which was in service at the time of the 1A CW pump maintenance window.

- A finding and an associated NCV described in Section 2OS1.4(1) involved the failure of personnel to follow established plant procedures and radiological practices with respect to HRAs. An individual signed in on a general area RWP, and subsequently entered a HRA to conduct a work in the Unit 2 drywell, contrary to plant Technical Specifications.

- A licensee-identified violation discussed in Section 4OA7 involved the failure of maintenance contractor personnel to adequately follow written work instructions regarding the removal of a U-bolt/pipe hanger for the Unit 2 reactor recirculation (RR) system in the Unit 2 drywell. The wrong U-bolt was removed, contrary to written job instructions in an approved work package; the error was subsequently discovered by the licensee and corrected several days later. While the missing U-bolt was determined to have been of no consequence for the established plant conditions, if left uncorrected it would have been consequential for RR pipe qualification during operation.

These human performance deficiencies were procedure compliance and adherence related.

4OA5 Other

Cornerstone: Mitigating Systems

.1 (Discussed) Unresolved Item 05000373/2004005-04; 05000374/2004005-04: Standby Liquid Control (SBLC) Boron Tank Volume/Concentration Measurements

One URI from a prior inspection report was discussed. This did not represent any inspection samples.

On November 19, 2004, the Unit 2 main control room received a SBLC tank level alarm. Plant operators concluded that the bubbler system that provides both tank level and alarm indications was plugged and required cleaning. After the bubbler was cleaned, however, the SBLC tank low level alarm still was actuated. A manual measurement conducted by operations personnel using a T-square indicated a tank volume of 4717 gallons. Since the low level alarm setpoint was at 4700 gallons, the licensee decided to add water to the SBLC tank to increase the volume of solution.

On November 23, 2004, operations and chemistry personnel added water to the Unit 2 SBLC tank and, as required by procedure, sampled the sodium pentaborate (boron solution) concentration afterwards. Volume was measured using the T-square at 4767 gallons and boron solution concentration was determined to be 12.99 percent. The minimum required Technical Specification boron solution concentration for this volume is 12.97 percent, per Technical Specification Figure 3.1.7-1. Chemistry technicians noted that there was little margin to the Technical Specification limit, and plans were made to perform a sodium pentaborate addition to the tank during the following week.

Just prior to midnight on November 25, 2004, Unit 2 operators were performing their daily Technical Specification surveillance to verify SBLC tank level within the limits of Technical Specification Figure 3.1.7-1. Measured tank volume was 4750 gallons. This volume was below the required Figure 3.1.7-1 limit for the current boron solution concentration of 12.99 percent. For a volume of 4750 gallons, Figure 3.1.7-1 specified a minimum boron solution concentration of 13.02 percent. SBLC tank volume was subsequently measured using the T-square, and 4762 gallons was the result. This volume was exactly at the Technical Specification Figure 3.1.7-1 limit for a boron solution concentration of 12.99 percent. However, questions by the on-watch operations crew raised doubt as to the accuracy of the T-square volume measurement when it was realized that an unauthorized operator aid in the form of a placard on the side of the SBLC tank was being used to convert inches measured with the T-square to tank volume in gallons. The conversion method on the placard was different than the calculation used by chemistry technicians specified in their approved plant procedures.

Using the approved calculation from a chemistry procedure, operators recalculated the SBLC tank volume from their T-square measurement and determined it to be 4757 gallons, which was once again below the Figure 3.1.7-1 limit. Both trains of SBLC were declared inoperable and the applicable Technical Specification 8-hour shutdown time clock entered. Chemistry technicians were called in to sample the SBLC boron solution tank concentration, and obtained a measured value of 13.11 percent. When compared with the T-square volume of 4757 gallons, this concentration value was within the limits of Technical Specification Figure 3.1.7-1 and both trains of SBLC were declared operable.

The licensee conducted an extent-of-condition review and determined that both Unit 1 and Unit 2 SBLC tanks had routinely been maintained with little margin to the Figure 3.1.7-1 limits for volume and boron solution concentration. The licensee has entered multiple issues associated with this event into their corrective action program (CRs 276755, 277113, 277439, 281247, and 281238). These condition reports have generated several corrective action program investigations, including a root cause report (RCR 276755) and an apparent cause evaluation (ACE 277113).

As of the publication of this inspection report, the inspectors continue to review the licensee's CAP and associated engineering documents for this issue. Initial reviews by the inspectors have yielded several questions regarding the licensee's methods for calculating SBLC tank volume. Over the course of the inspection period, the licensee's engineering staff have developed several similar methods for calculating SBLC tank volume, each in an attempt to demonstrate that no past violations of Technical Specification requirements had occurred with respect to measured sodium pentaborate concentration and volume. The issue remains unresolved pending completion of the inspectors' reviews of the licensee's calculations. (URI 05000373/2004005-04; 05000374/2004005-04)

4OA6 Meetings

.1 Exit Meeting

The inspectors presented the inspection results to the Site Vice President, Ms. S. Landahl, and other members of licensee management on April 5, 2005. The inspectors discussed the controls associated with a single proprietary engineering evaluation from General Electric Company that was reviewed by the inspectors. No other proprietary information was identified.

.2 Interim Exit Meetings

Interim exits were conducted for:

- A refuel outage baseline radiation protection inspection with the Site Vice President, Ms. S. Landahl, and other members of the licensee's staff on February 18, 2005.

- A refuel outage baseline engineering inspection of ISI with the Site Vice President, Ms. S. Landahl, and other members of the licensee's staff on March 1, 2005.

- A baseline emergency preparedness inspection with the Site Vice President, Ms. S. Landahl, and other members of the licensee's staff on March 25, 2005.

4OA7 Licensee-Identified Violations

Cornerstones: Barrier Integrity and Emergency Preparedness

The following violations of very low significance were identified by the licensee and are violations of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as NCVs.

- Criterion V of 10 CFR 50, Appendix B, "Procedures, Instructions, and Drawings," requires that activities affecting quality be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances, and that activities be accomplished in accordance with these instructions, procedures, or drawings. Contrary to these requirements, on February 16, 2005, contractor maintenance personnel removed a U-bolt from a reactor recirculation (RR) system pipe support in the Unit 2 drywell that was not the U-bolt specified in their approved work instructions. The error was discovered on February 19, 2005, by the licensee and corrected.

  Inspectors determined that the issue was of more than minor significance because if left uncorrected it would have become a more significant safety concern. Specifically, while the missing U-bolt was determined to have been of no consequence for the established plant conditions, if left uncorrected it would have been consequential for RR piping qualification during operation. Because there were no actual consequences associated with the issue, the inspectors determined it to be of very low significance and within the licensee's response band. The licensee had entered the issue into their CAP as IR 303383.

- Part 50.47 of 10 CFR, paragraph (b)(15), requires, in part, that radiological emergency response training be provided to those who may be called on to assist in an emergency. Table B-1 of the licensee's standardized emergency plan required that the minimum on-shift staffing included two radiation protection (RP) personnel for in-plant protective actions. In September 2004, EP staff based at another of the licensee's Illinois nuclear stations identified that this emergency plan commitment was met during weekends and holidays by one on-shift RP technician and one on-shift chemistry technician. However, the licensee also determined that chemistry technicians' training had evolved such that the training no longer met all requirements to provide in-plant protection actions.

  In early December 2004, the licensee completed an adequate root cause investigation of this concern's impact at each of its Illinois nuclear stations. Timely corrective actions included assigning two RP technicians on all back shifts, initiating revision of the standardized ERO training procedure, and initiating an assessment of ERO position qualifications in cases where some ERO training was being performed by other departments. Because no actual emergency events had occurred that required in-plant protective actions and the licensee’s timely corrective actions included staffing a minimum of two RP technicians on-shift, this violation is not more than of very low significance, and is being dispositioned as an NCV.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

S. Landahl, Site Vice President
D. Enright, Plant Manager
J. Bearden, Emergency Planning Coordinator
T. Connor, Maintenance Director
L. Coyle, Operations Director
D. Czufin, Site Engineering Director
C. Dieckmann, Training Manager
A. Ferko, Nuclear Oversight Manager
F. Gogliotti, System Engineering Manager
P. Holland, Regulatory Assurance - NRC Coordinator
B. Kapellas, Radiation Protection Manager
A. Kochis, ISI Coordinator
H. Madronero, Engineering Programs Manager
C. Minor, NDE Level III
W. Riffer, Emergency Planning Manager
T. Simpkin, Regulatory Assurance Manager
C. Wilson, Station Security Manager

Nuclear Regulatory Commission

B. Burgess, Chief, Reactor Projects Branch 2

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000374/2005002-01	NCV	Failure to Properly Implement Procedure Requirements for Hot Work and Ignition Control Results in a Fire in the 2B RHR Corner Room (Sections 1R05.2 and 4OA4)
05000373/2005002-02	NCV	Failure to Assess and Manage Risk Associated with the 1A Circulating Water Pump Electrical Meter Replacement Results in the Trip of the 1C Circulating Water Pump (Sections 1R13.2 and 4OA4)
05000373/2005002-03	NCV	Failure to Assess and Manage Risk Associated with the Cycling of the 1DG032 Manual Gate Valve Results in Inoperable and Unavailable ECCS Components (Section 1R13.3)
05000374/2005002-04	NCV	Failure to Incorporate Relevant Design Information into Battery Charger Operating Procedure Results in DC Bus Undervoltage Condition (Section 1R19.2)
05000373/2005002-05	URI	Unit 1 CSCS Pump Room Ventilation System Control Cabinet Water Intrusion (Section 1R19.3)
05000374/2005002-06	NCV	Electrician Enters HRA (Drywell) When Signed On To General Area RWP (Sections 2OS1.4(1) and 4OA4)
05000374/2005002-07	URI	Contractor Pipefitters Enter Condenser Pit HRA Without Required RP Briefing (Section 2OS1.4(2))
05000374/2005002-08	NCV	Failure to Take Timely and Effective Corrective Action for Hot Work Ignition Control Issues (Section 4OA2.1)
05000374/2005002-09	NCV	Failure to Take Timely and Effective Corrective Action for Emergency Diesel Generator (EDG) Reverse Power Trips Results in Additional EDG Inoperability and Unavailability (Section 4OA2.2)
05000373/2005002-10 05000374/2005002-10	URI	Single Failure Vulnerability of Safety Related 4160 Vac Division 1 and Division 2 Protective Relay Circuitry (ENS 41366) (Section 4OA3.1)
05000373/2005002-11	URI	Unit 1 Reactor Power Excursion to 103.18 Percent (Section 4OA3.2)

Closed

05000374/2005002-01	NCV	Failure to Properly Implement Procedure Requirements for Hot Work and Ignition Control Results in a Fire in the 2B RHR Corner Room (Sections 1R05.2 and 4OA4)
05000373/2005002-02	NCV	Failure to Assess and Manage Risk Associated with the 1A Circulating Water Pump Electrical Meter Replacement Results in the Trip of the 1C Circulating Water Pump (Sections 1R13.2 and 4OA4)
05000373/2005002-03	NCV	Failure to Assess and Manage Risk Associated with the Cycling of the 1DG032 Manual Gate Valve Results in Inoperable and Unavailable ECCS Components (Section 1R13.3)
05000374/2005002-04	NCV	Failure to Incorporate Relevant Design Information into Battery Charger Operating Procedure Results in DC Bus Undervoltage Condition (Section 1R19.2)
05000374/2005002-06	NCV	Electrician Enters HRA (Drywell) When Signed On To General Area RWP (Sections 2OS1.4(1) and 4OA4)
05000374/2005002-08	NCV	Failure to Take Timely and Effective Corrective Action for Hot Work Ignition Control Issues (Section 4OA2.1)
05000374/2005002-09	NCV	Failure to Take Timely and Effective Corrective Action for Emergency Diesel Generator (EDG) Reverse Power Trips Results in Additional EDG Inoperability and Unavailability (Section 4OA2.2)

Discussed

05000373/2004005-04 05000374/2004005-04	URI	SBLC Tank Level and Boron Solution Concentration Measurement Issues (Section 4OA5)

LIST OF DOCUMENTS REVIEWED

1R01 Adverse Weather Protection

Procedures:
- LOA-TORN-001; High Winds/ Tornado; Revision 4
- OP-AA-108-111; Adverse Condition Monitoring and Contingency Planing; Revision 1
- OP-AA-108-111-1001; Severe Weather Guidelines; Revision 1

1R04 Equipment Alignment

Issue Reports:
- 141023; Apparent Failure of Div. II CSCS Room Temperature Controller; 1/24/2003
- 154515; Div 3 CSCS Pump Room Fans Did Not Secure Following EDG Run; 4/17/2003
- 236085; Errors in Analysis Affecting Max Anticipated CSCS Rm Temp; 7/14/2004
- 266846; Love Controller Replacement; 10/25/2004
- 283233; 1TIC-VY017 Reads Low; 12/16/2004
- 287334; Temperature Controller is Erratic, Not Giving True Readings; 1/3/2005
- 287351; Conduit Has a Leak Up at the Roofline - Causing 1TIC-VY024; 1/04/2005
- 287694; Ref. Issue Report #287351 WO # 769178-01; 1/4/2005
- 287742; Water in Local Control Panel 1PL73J; 1/5/2005
- 287987; FIN Follow-Up from Troubleshooting 1TIC-VY024 Erratic Ind; 1/5/2005
- 301768; Water Identified in Junction Boxes Feeding 1PL73J; 2/15/2005
- 302014; (NRC Identified) Discrepancy Between OPS Lesson Plan and UFSAR; 2/16/2005
- 307568; 2E12-F353C Div 2 CSCS RHR Root Valve Leaks By Excessively; 3/2/2005
- 308000; Install Drain Hole in J-Box for Damper Motor 0TZ-VD00; 3/3/2005

Operability Evaluation:
- OE 96155; Clarification of 1(2)VY05C Operability to Support DG Operations; 11/23/1996

Procedures:
- LOP-FC-02E; Unit 2 Fuel Pool Cooling Electrical Checklist; Revision 3
- LOP-FC-02M; Unit 2 Fuel Pool Cooling Mechanical Checklist; Revision 6
- LOP-DG-06E; Unit 1 A DG Cooling System Electrical Checklist; Revision 5
- LOP-DG-06M; Unit 1 A Diesel Generator Cooling System Mechanical Checklist; Revision 12
- LOP-DG-07E; Unit 1 B Diesel Generator Cooling System Electrical Checklist; Revision 5
- LOP-DG-07M; Unit 1 B Diesel Generator Cooling System Mechanical Checklist; Revision 11
- LOP-DG-08E; Unit 0 Diesel Generator Cooling System Electrical Checklist; Revision 8
- LOP-DG-08M; Unit 0 Diesel Generator Cooling System Mechanical Checklist; Revision 18
- LOP-DG-09E; Unit 2 A Diesel Generator Cooling System Electrical Checklist; Revision 4

- LOP-DG-09M; Unit 2 A Diesel Generator Cooling System Mechanical Checklist; Revision 7
- LOP-DG-10E; Unit 2 B Diesel Generator Cooling System Electrical Checklist; Revision 4
- LOP-DG-10M; Unit 2 B Diesel Generator Cooling System Mechanical Checklist; Revision 9
- LOP-RH-04E; Unit 2 Residual Heat Removal System Electrical Checklist; Revision 14
- LOP-RH-2BM; Unit 2 B Residual Heat Removal System Mechanical Checklist; Revision 0
- LOP-RH-2CM; Unit 2 C Residual Heat Removal System Mechanical Checklist; Revision 0
- LOP-RHWS-1AM; Unit 1 A RHR Service Water System Mechanical Checklist; Revision 1
- LOP-RHWS-1BM; Unit 1 B RHR Service Water System Mechanical Checklist; Revision 3
- LOP-RHWS-2AM; Unit 2 A RHR Service Water System Mechanical Checklist; Revision 1
- LOP-RHWS-2BM; Unit 2 B RHR Service Water System Mechanical Checklist; Revision 2
- LOP-VD-01E; Unit 1 A Diesel Ventilation System Electrical Checklist; Revision 7
- LOP-VD-02E; Unit 2 A Diesel Ventilation Electrical Checklist; Revision 6
- LOP-VD-03E; Unit 1 Diesel Vent (VD) Electrical Checklist; Revision 5
- LOP-VD-04E; Unit 2 B Diesel Generator Ventilation Electrical Checklist; Revision 5
- MA-MW-726-022; Electrical Cable Termination and Inspection; Revision 0

Work Orders:
- 536202; Apparent Failure of Controller 1TIC-VY024; 1/24/2003
- 769178; Apparent Failure of Controller 1TIC-VY024; 1/04/2005
- 770108; Water in Local Control Panel 1PL73J; 1/12/2005
- 743426; Install/Remove Temp. Level Indication for LLP-2004-007; 3/6/2005

Updated Final Safety Analysis Report; Revision 15:
- Chapter 9, Auxiliary Systems
- Chapter 6, Section 6.3.2.2.4 - LPCI subsystem

1R05 Fire Protection

Procedures:
- CC-AA-201; Plant Barrier Control Program; Revision 5
- OP-MW-201-004; Fire Prevention for Hot Work; Revision 0
- OP-MW-201-007; Fire Protection System Impairment Control; Revision 3
- OP-AA-201-001; Fire Marshal Tours; Revision 2
- OP-AA-201-008; Pre-Fire Plans; Revision 1
- OP-AA-201-009; Control of Transient Combustible Material; Revision 4
- LS-AA-128; Regulatory Review of Proposed Changes to the Approved Fire Protection Program; Revision 0
- LOS-FP-D1; Fire Protection Door Daily Surveillance; Revision 2

Issue Reports:
- 302209; Small Fire in Unit 2 Reactor Building – 694' Elevation; 2/16/2005
- 302447; Near Miss – Fire Extinguisher Malfunction; 2/16/2005
- 304516; (NRC Identified) RHR Keep Fill Modification Fire Protection Awareness; 2/23/2005

Control Room Time Clock Tracking Sheet for Fire Watch Active Patrols; 2/9/2005 - 2/11/2005

Fire Protection Impairment Permits:
- 2-04-189-TRM
- 2-04-146-TRM
- 2-02-056-TRM

Plant Barrier Impairment Permits:
- DR-500.00r5
- 2B DG Access Hatch.00r5
- FP U2 DG Corridor L-21.01r5
- FP U2 DG Corridor L-21.00r5
- DR-503.00r5

Fire Watch Inspection Logs; 2/9/2005 - 2/11/2005

Pre-Fire Plans for Fire Zones 4F1, 4E1, and 4E3

La Salle County Nuclear Station Fire Protection Report Vol. 1:
- H.3.4.12 : Unit 1 Auxiliary Equipment Room - Fire Zone 4E1
- H.3.4.14 : Unit 1 Division 2 Essential Switchgear Room - Fire Zone 4E3
- H.3.4.16 : Unit 1 Division 1 Essential Switchgear Room - Fire Zone 4F1

Technical Requirements Manual :
- Vol. 4, Section 3.3p; Fire Detection Instrumentation

Updated Final Safety Analysis Report:
- Fig. 9.5-1 Fire Protection System; Sheets 17 and 22

<u>1R08</u> <u>Inservice Inspection Activities</u>

Issue Reports:
- 303540; (NRC-Identified) Extent of Condition Review for IR 142187; 2/20/2005
- 142187; Pipe Support FW02-2875C Found Damaged; 1/31/2003
- 195554; Rejectable Indication on VT-3 Examination of FW02-1158X; 1/15/2004
- 195712; Snubber NB13-1001-S Failed on High Drag; 1/15/2004
- 195988; UT Indications in LP and HP Piping Inside the Reactor; 1/17/2004
- 196074; Additional UT Indications in LPCS Piping Inside the Reactor; 1/18/2004
- 212765; Error in LPCS Flaw Sizing Calculation; 4/1/2004

EC 341014; Evaluation of Bent FW Pipe Clamp M09-FW02-2875C; Revision 0

Operating Experience:
- NRC IN 2004-08: Reactor Coolant Pressure Boundary Leakage Attributable to Propagation of Cracking in Reactor Vessel Nozzle Welds
- G.E. RICSIL 082: Core Spray Nozzle to Safe End Weld Leak; AIR No. 373-458-97-00082.00

Nondestructive Examinations:
- Magnetic Particle Examination Data Sheet Report No. 2R10-109; Component RH40-2877X; 2/28/2005
- UT Examination Summary Sheet No: 2R09-010, WO No: 430431; Weld ID: LCS-2-BH; 2/3/2003
- UT Examination Summary Sheet No: 2R09-015, WO No: 430431; Weld ID: LCS-2-N4D; 1/30/2003
- UT Examination Summary Report No. 2R10-010; Component ID: LCS-2-N2B, Recirculation Inlet Nozzle; 2/28/2005

Work Order:
- 96094687; Replace 2E12-F325B/326B Double Block Valves with Two Single Valves; 9/24/2002

Prints and Drawings:
- ISI-RH-2009; Inservice Inspection Isometric, Residual Heat Removal System, Unit 2; Revision B
- M09-RH40-2877X, Sheet 1; Pipe Support, Residual Heat Removal System, Unit 2; Revision F

Procedures:
- GE-UT-705; Procedure for the Examination of Reactor Pressure Nozzle Inner Radius and Nozzle to Vessel Welds with the GERIS 2000 OD in Accordance with Appendix VIII; Version No. 4
- MT-EXLN-102V0; Procedure for Magnetic Particle Examination Using AC Yoke, Dry Powder, or Wet Visible; Revision 2

1R11 Licensed Operator Requalification Program

Licensed Operator Requalification Scenario Guide:
- ESG 64; Revision 0

TQ-AA-106; Licensed Operator Requal Training Program; Revision 6

1R12 Maintenance Effectiveness

Sodium Pentaborate Sample Results for Unit 1 and Unit 2 SBLC Storage Tanks; June 2004 - December 2004

Engineering Changes:
- 338147; SBLC Tank Level; Revision 0
- 352973; SBLC Tank Level Tee Square; Revision 0

- 353491; Engineering Determination of Volume Via Gallons per Inch of Height in the Units 1&2 SBLC Storage Tank (EPN) 1(2) C41-A001; Revisions 0 & 1

Procedures:
- CC-AA-103-2001; Set point Change Control; Revision 2
- CY-AA-130-200; Quality Control; Revision 6
- LCP-110-9; Determination of High Range Boron (Sodium Pentaborate); Revision 22
- LCP-310-09; Standby Liquid Control Tank Sampling; Revision 8
- LOP-SC-05; Changing Sodium Pentaborate Concentration in Standby Liquid Control (SBLC) Solution Tank; Revision 18

Information Notice 86-48; Inadequate Testing of Boron Solution Concentration in the Standby Liquid Control System; 6/13/1986

Issue Reports:
- 083484; SLC System Operability During Air Tank Sparging; 11/20/2001
- 276560; No Procedure Guidance for Sodium Pentaborate Addition Calculation; 11/24/2004
- 276755; SBLC Concentration Limits Outside TA limits; 11/25/2004
- 276839; NRC Identified Point of Discovery for SBLC Inop; 11/26/2004
- 277113; Unauthorized Operator Aid Found on Standby Liquid Control (SBLC) Solution Tank; 11/26/2004
- 277439; NRC Identified Issue with Use of “T” Square for SBLC Tank Level; 11/29/2004
- 281238; Standby Liquid Control Solution Tank Volume Determination; 12/10/2004
- 281244; UFSAR Sections Not Up to Date for Standby Liquid Control to Include Low-Level Alarm and Technical Specification 3.1.7 (Standby Liquid Control Figures); 12/10/2004
- 281247; Chemistry Procedures Not Up to Date for Technical Specification 3.1.7 (Standby Liquid Control Figures); 12/10/2004
- 283765; Sodium Pentaborate Concentration Outside Optimum Range; 12/17/2004
- 296489; SBLC Volume Resample Not Routed for Ops Review; 2/1/2005

1R13 Maintenance Risk Assessments and Emergent Work Control

Engineering Change:
- EC 353657; Isolation of Metering to Common 141Y/142Y and 241Y/242Y Safety Related Buses; Revision 0

Issue Reports:
- 141023; Apparent Failure of Div. II CSCS Room Temperature Controller; 1/24/2003
- 154515; Div 3 CSCS Pump Room Fans Did Not Secure Following EDG Run; 4/17/2003
- 236085; Errors in Analysis Affecting Max Anticipated CSCS Rm Temp; 7/14/2004
- 266846; Love Controller Replacement; 10/25/2004
- 283104; HPCS DG Room Pressurized During DG Start; 12/16/2004
- 283233; 1TIC-VY017 Reads Low; 12/16/2004
- 286665; Stem to Disc Separation on 1DG032; 12/30/2004
- 287334; Temperature Controller is Erratic, Not Giving True Readings; 1/3/2005
- 287351; Conduit Has a Leak Up at the Roofline - Causing 1TIC-VY024; 1/4/2005

- 287541; 1C Circ Water Pump Tripped; 1/4/2005
- 287694; Ref. Issue Report #287351 WO # 769178-01; 1/4/2005
- 287742; Water in Local Control Panel 1PL73J; 1/5/2005
- 287987; FIN Follow-Up from Troubleshooting 1TIC-VY024 Erratic Ind; 1/5/2005
- 290618; CSCS Valve PM's Critical Prior to L1R11 Need Deferral; 1/13/2005
- 293279; U-1 DWFD FUR 1UR-RF002 Pen 1 Ind > 1 GPM Above Alternate; 1/22/2005
- 297076; Vulnerability of Division 1 & 2 Protective Relay Circuitry; 2/4/2005
- 299188; Lack of Minimum 6-inch Physical Separation in Division 1 & 2 CTs; 2/8/2005
- 303991; DWFD Sump Flow Indication Pegged Upscale; 2/22/2005
- 304111; Possible Failed Instrument (Level Switch) 1C11-N013B; 2/22/2005
- 304853; Troubleshooting Results for Unit 1 SDV 1/2 Scram; 2/24/2005

Procedures:
- LOA-CW-101; Unit 1 Circulating Water System Abnormal; Revision 11
- LOR-1PM03-J-B406; Circulating Water Pump 1CW01P A/B/C Auto Trip; Revision 3
- LOP-CW-03; Startup and Operation of the Circulating Water System; Revision 26
- LOP-CW-09; Circulating Water System Ice Melting; Revision 13
- LOR-1PM13J-A301; Drywell Floor Drain Sump Level Hi, Hi Hi, or Pump Start Failure; Revision 4
- LIS-PC-121; Unit 1 Drywell Floor Drain Sump Discharge Flow Calibration; Revision 1
- LOS-AA-S101; Unit 1 Shiftly Surveillence; Revision 28
- LOS-DG-Q1; '0' Diesel Generator Auxiliaries Inservice Test; Revision 38
- LSCS P.G. No. 130; Equipment to Be Worked Around the Clock; Revision 0

Corporate RCR 299641; Single Failure Vulnerability of Safety Related Division 1 & 2 Protective Relay Circuitry Root Cause Analysis; 3/8/2005

Operability Evaluation:
- OE 05-001; Minimum 6-inch Physical Separation in Division 1 & 2 CTs; Revision 0

Work Order:
- 545611-01; IM Contingency for DWFD Loop Instruments; 2/22/2005

1R14 Operator Performance During Non-Routine Plant Evolutions and Events

Issue Reports:
- 297076; Vulnerability of Division 1 & 2 Protective Relay Circuitry; 2/4/2005
- 298353; 2B-33 F067B Steam Coming From Packing Around Stem; 2/7/2005
- 298462; 2B RR PP Discharge Valve Would Not Stroke Closed; 2/7/2005
- 299188; Lack of Minimum 6-inch Physical Separation in Division 1 & 2 CTs; 2/8/2005
- 300143; 2B33-F067B Failed to Close; 2/9/2005
- 305823; SDC Not in Operation; 2/26/2005

Corporate RCR 299641; Single Failure Vulnerability of Safety Related Division 1 & 2 Protective Relay Circuitry Root Cause Analysis; 3/8/2005

Engineering Change:
- EC 353657; Isolation of Metering to Common 141Y/142Y and 241Y/242Y Safety Related Buses; Revision 0

Unit 2 Operator Logs; 2/7/2005

Operability Evaluation:
- OE 05-001; Minimum 6-inch Physical Separation in Division 1 & 2 CTs; Revision 0

Procedures:
- LOA-CW-101; Unit 1 Circulating Water System Abnormal; Revision 11
- LOP-CW-03; Startup and Operation of the Circulating Water System; Revision 26
- LOP-CW-09; Circulating Water System Ice Melting; Revision 13
- LOP-RR-09; Reactor Recirc Pump Shutdown; Revision 21
- LOR-1PM03-J-B406; Circulating Water Pump 1CW01P A/B/C Auto Trip; Revision 3

1R15 Operability Evaluations

Issue Reports:
- 288363; Results of Lisega Snubber Test Results; 1/6/2005
- 287334; Temperature Controller is Erratic, Not Giving True Readings; 1/3/2005
- 287742; Water in Local Control Panel 1PL73J; 1/5/2005
- 287987; FIN Follow-Up from Troubleshooting 1TIC-VY024 Erratic Ind; 1/5/2005
- 301768; Water Identified in Junction Boxes Feeding 1PL73J; 2/15/2005

Engineering Evaluation:
- Report No. R93-007S; Engineering Evaluation of NRC IE Notice 89-63 for LaSalle County, Dresden, and Quad Cities Stations All Units; Revision 0

NRC Information Notice:
- 89-63; Possible Submergence of Electrical Circuits Located Above the Flood Level Because of Water Intrusion and Lack of Drainage; 9/5/1989

Operability Evaluations:
- OE 04-008; Lisega Snubbers; Revision 3
- OE 04-007; Degraded Fans on Transformer 236Y; Revision 1

Engineering Changes:
- 332208; Evaluation of Appendix J Testing Requirements on the Standby Liquid Control System; Revision 0
- 354196; L2R10 Lost Parts Evaluation for Items That Could Reach the Reactor Vessel; Revision 0
- 354344; L2R10 Refuel Outage Nuclear Fuels Lost Parts Evaluation; Revision 0

1R16 Operator Workarounds

Issue Reports:
- 311171; Multiple TS 3.6.4.1 Entries Due to U2 VR System Operation; 3/10/2005
- 311529; Unexpected Change in Reactor Building Differential Pressure; 3/11/2005

- 311672; Unit 1 VR Exh Flow Oscillates with Constant Signal to Damper; 3/11/2005
- 311795; L2R10 LL : VR System and RB DP Oscillations; 3/12/2005
- 312176; Sudden Increase (More Negative) in RB DP; 3/13/2005

Engineering Change:
- 352527; MR90 Review to Maintain VR DP During Troubleshooting of VR; Revisions 0 & 1

Procedures:
- CC-AA-102; Design Input and Configuration Change Impact Screening; Revision 9
- LOP-VR-01; Reactor Building Ventiallation System Startup and Operation; Revision 31
- LS-AA-104; Exelon 50.59 Review Process; Revision 4

Work Order:
- 731302-11; Replace/ Calibrate U-2 VR Supply Instruments; 3/7/2005

1R17 Permanent Plant Modifications

Calculations:
- GEN 01-002; Generic Lead Shielding Blanket & Support Detail Qualification; Revision 0
- L-002804; Installation of Permanent Lead Shielding Blankets Inside Unit 2 Drywell; Revision 1

Engineering Changes:
- 342975; Unit 2 Residual Heat Removal Service Water Keep Fill Elimination; Revision 4
- 343542; Replace Carbon Steel CSCS Valves with Stainless Steel Valves ; Revision 2
- 332685; Install Permanent Lead Shielding in Unit 2 Drywell; Revision 1
- 353949; Alternate Detail for the Steam Dryer Lifting Lug Upper Support; Revision 0

Procedure:
- CC-AA-102; Design Input & Configuration Change Impact Screening; Revision 9

1R19 Post-Maintenance Testing

Issue Reports:
- 292281; Div 1 125 VDC Transient During Charger Swap; 1/19/2005
- 293279; U-1 DWFD FUR 1UR-RF002 Pen 1 Ind > 1 GPM Above Alternate; 1/22/2005
- 293389; LOP-DC-01 Revision; 1/23/2005
- 295228; Hi Voltage During U2 Division 1 Charger Swap; 1/28/2005
- 297795; Difference in 125VDC Divisional Charger Metering; 2/4/2005
- 298477; 'A' RPS Half Scram During LOS-RP-W1 - IN Disc Rupture; 7/7/2005
- 298631; IN Rupture Disk Blew on Loss of 'A' RPS; 2/7/2005
- 317267; NRC Identifies Water Dripping from Weep Hole in VY JB; 3/25/2005

Engineering Changes:
- 340584; Evaluate Acceptability of Energizing Both 125 VDC Division 1 or 2 Battery Chargers Simultaneously to Support Battery Charger Testing; Revision 0
- 346528; Provide Guidance for the Use of Intermittent Loads; Revision 0

Engineering Change Request:
- 368281; Battery Charger Troubleshooting as an Intermittent Load; 1/21/2005

Procedures:
- CC-AA-308; Control and Tracking of Electrical Load Changes; Revision 4
- LES-DC-103A; Division I Battery Charger Capacity Test; Revision 11
- LIS-PC-121; Unit 1 Drywell Floor Drain Sump Discharge Flow Calibration; Revision 1
- LOP-DC-01; Battery Charger Startup and Shutdown; Revisions 25 & 26
- LOR-1PM13J-A301; Drywell Floor Drain Sump Level Hi, Hi Hi, or Pump Start Failure; Revision 4
- LOS-AA-S101; Unit 1 Shiftly Surveillence; Revision 28

Work Orders:
- 545611-01; IM Contingency for DWFD Loop Instruments; 2/22/2005
- 734945-02; Potentially Degraded RPIS Circuit Cards due to Diodes; 1/26/2005
- 774091-02; EM Replace 2A RPS Voltage Regulator; 2/15/2005

<u>1R20</u> <u>Outage Activities</u>

Issue Reports:
- 298740; SRM “D” Detector Stuck Withdrawn; 2/8/2005
- 298741; IRM “D” Stuck Inserted; 2/8/2005
- 298322; Received “B” Half Scram Due to “H” IRM Hi=Hi; 2/7/2005
- 299196; Operator Injury During U-2 Div 3 CSCS Work; 2/8/2005
- 300701; Wrong Unit Error; 2/12/2005
- 307158; Lead Pump on the Div 2 CSCS Sump Found in the Stop Pos; 3/2/2005
- 307578; 2E12-F050A Fails High Pressure Water Leak Test; 3/2/2005
- 307589; L2R10 LL: 2B21-F032A Repair After Unacceptable LLRT Result; 3/2/2005
- 311369; Crud Burst Resulted in Increased Dose Rates on Refuel Floor; 3/11/2005
- 314018; Low Bearing Oil Pressure, Suspect Leak/ Hole in Pipe; 3/17/2005

Procedures:
- LGP-2-1; Normal Unit Shutdown; Revision 65
- LGP-1-1; Normal Unit Startup; Revision 73
- LGP1-S1; Master Startup Checklist; Revision 55
- LOA-RR-201; Unit 2 Recirculation Pump System Abnormal; Revision 13
- LIS-RR-205A; Unit 2 Recirculation Pump Trip System A Breaker Arc Suppression Response Time Testing; Revision 7
- LES-RP-101; RPS MG Set Startup and Operation; Revision 9
- LOP-DW-02; Drywell Entry and Inspection (Shutdown, Startup or Operation); Revision 13
- LOP-DW-01; Drywell Close Out (After Outage); Revision 38
- OP-AA-108-108-1001; Drywell/Containment Closeout; Revision 0
- LOS-DG-209; Unit 2 Integrated Division I Response Time Surveillance; Revision 1A
- LOS-DG-210; Unit 2 Integrated Division II Response Time Surveillance; Revision 1
- LOS-DG-211; Unit 2 Integrated Division III Response Time Surveillance; Revision 0

L2R10 Shutdown Safety Management Program

10 CFR 50.59 Screenings and Evaluations:
- L05-73; LaSalle Unit 2 Cycle 11 Reload Package; Revision 0
- L05-74; LaSalle Unit 1 and 2 GE-14 Fuel Implementation; Revision 0

1R22 Surveillance Testing

Engineering Changes:
- 338147; SBLC Tank Level; Revision 0
- 352973; SBLC Tank Level Tee Square; Revision 0
- 353491; Engineering Determination of Volume Via Gallons per Inch of Height in the Units 1&2 SBLC Storage Tank (EPN) 1(2) C41-A001; Revisions 0 & 1

Engineering Change Request:
- 352281; Provide Information in Eng Change or Equivalent on Delta Between V-Notch and the Totalizer; 10/09/2001

Information Notice 86-48; Inadequate Testing of Boron Solution Concentration in the Standby Liquid Control System; 6/13/1986

Issue Reports:
- 083484; SLC System Operability During Air Tank Sparging; 11/20/2001
- 276560; No Procedure Guidance for Sodium Pentaborate Addition Calculation; 11/24/2004
- 276755; SBLC Concentration Limits Outside TA limits; 11/25/2004
- 276839; NRC Identified Point of Discovery for SBLC Inop; 11/26/2004
- 277113; Unauthorized Operator Aid Found on Standby Liquid Control (SBLC) Solution Tank; 11/26/2004
- 277439; NRC Identified Issue with Use of “T” Square for SBLC Tank Level; 11/29/2004
- 281238; Standby Liquid Control Solution Tank Volume Determination; 12/10/2004
- 281244; UFSAR Sections Not Up to Date for Standby Liquid Control to Include Low-Level Alarm and Technical Specification 3.1.7 (Standby Liquid Control Figures); 12/10/2004
- 281247; Chemistry Procedures Not Up to Date for Technical Specification 3.1.7 (Standby Liquid Control Figures); 12/10/2004
- 283765; Sodium Pentaborate Concentration Outside Optimum Range; 12/17/2004
- 287208; DWFDS Fillup Rate High; 1/03/2005
- 290678; Noble Gas Channel Alarm Will Not Clear; 1/14/2005
- 291499; DWFDS Fillup Rate Reading 1.1 GPM; 1/18/2005
- 293279; U-1 DWFD FUR 1UR-RF002 Pen 1 Ind > 1 GPM Above Alternate;1/22/2005
- 296489; SBLC Volume Resample Not Routed for Ops Review; 2/1/2005
- 298625; MSL Drain Valves 2B21-F019/F016 Failed LLRT in LTS 100-4; 2/7/2005
- 301672; Feedwater Check Valve 2B21-F032A Failed As-Found LLRT; 2/14/2005
- 304012; Anomolies Noted During LES-SC-201 Surveillance; 2/22/2005
- 304021; Problems Encountered During the Performance of LES-SC-201; 2/22/2005
- 307210; SBLC Circuit Continuity Loss Fuse Found Blown; 3/2/2005
- 307242; Opposite Division Fuse Blown Following LOS-SC-R1; 3/2/2005
- 309172; L2R10 LL: SBLC Issues During L2R10; 3/6/2005

Procedures:
- CC-AA-103-2001; Set point Change Control; Revision 2
- CY-AA-130-200; Quality Control; Revision 6
- LCP-110-9; Determination of High Range Boron (Sodium Pentaborate); Revision 22
- LCP-310-09; Standby Liquid Control Tank Sampling; Revision 8
- LOP-SC-05; Changing Sodium Pentaborate Concentration in Standby Liquid Control (SBLC) Solution Tank; Revision 18
- LOS-DG-209; Unit 2 Integrated Division I Response Time Surveillance; Revision 1
- LOS-DG-210; Unit 2 Integrated Division II Response Time Surveillance; Revision 1
- LOS-DG-211; Unit 2 Integrated Division III ECCS Response Time Surveillance; Revision 0
- LOS-SC-R5; SBLC Pump Full Flow/Pressure Test; Revision 2
- LOS-SC-Q1; SBLC Pump Operability/Inservice Test and Explosive Valve Continuity Check; Revision 21
- LMP-SC-01; SBLC Explosive Valve Maintenance; Revision 14
- LTS-100-3; Main Steam Isolation Valve Local Leak Rate Test; Revision 17
- LTS-100-10; Inboard/Outboard Feedwater Check Valves and Outboard Stop Valves Local Leak Rate Test; Revision 17
- LTS-300-5; Primary Containment Leak Rate Testing Program; Revision 35
- LTS-900-6; RHR Shutdown Cooling Return Pressure Isolation Valve Water Leak Rate Test; Revision 19
- LTS-900-12; RHR Primary Isolation Valve Water Leak Rate Test; Revision 19

Sodium Pentaborate Sample Results for Unit 1 and Unit 2 SBLC Storage Tanks; June 2004 - December 2004

Work Orders:
- 606950-01; OP Integrated Divisional Response Time Test IAW LOS-DG-210; 2/25/2005
- 607327-01; LOS-DG-209 Integrated Div 1 ECCS Response Time Pumps and Diesel; 2/23/2005
- 608104-01; LOS-DG-211 Integrated Div 3 ECCS Response Time Pumps and Diesel; 2/20/2005
- 759299-01; OP LOS-SC-Q1 2A SBLC Pump Quarterly Att 2A; 3/4/2005

1R23 Temporary Plant Modifications

10 CFR 50.59 Safety Evaluations:
- L01-0227; TMOD for an Alternate Means of Measuring the DW Floor Drain Sump Flow Rate; Revision 1

Corporate RCR 299641; Single Failure Vulnerability of Safety Related Division 1 & 2 Protective Relay Circuitry Root Cause Analysis; 3/8/2005

Issue Reports:
- 286665; Stem to Disc Separation on 1DG032; 12/30/2004
- 287208; DWFDS Fillup Rate High; 1/03/2005
- 290618; CSCS Valve PM’s Critical Prior to L1R11 Need Deferral; 1/13/2005

- 290678; Noble Gas Channel Alarm Will Not Clear; 1/14/2005
- 291499; DWFDS Fillup Rate Reading 1.1 GPM; 1/18/2005
- 292281; Div 1 125 VDC Transient During Charger Swap; 1/19/2005
- 293279; U-1 DWFD FUR 1UR-RF002 Pen 1 Ind > 1 GPM Above Alternate; 1/22/2005
- 293389; LOP-DC-01 Revision; 1/23/2005
- 295228; Hi Voltage During U2 Division 1 Charger Swap;1/28/2005
- 297076; Vulnerability of Division 1 & 2 Protective Relay Circuitry; 2/4/2005
- 297795; Difference in 125VDC Divisional Charger Metering; 2/4/2005
- 299188; Lack of Minimum 6-inch Physical Separation in Division 1 & 2 CTs; 2/8/2005

Engineering Change Requests:
- 352281; Provide Information in Eng Change or Equivalent on Delta Between V-Notch and the Totalizer; 10/09/2001
- 368281; Battery Charger Troubleshooting as an Intermittent Load; 1/21/2005

Engineering Changes:
- 340584; Evaluate Acceptability of Energizing Both 125 VDC Division 1 or 2 Battery Chargers Simultaneously to Support Battery Charger Testing; Revision 0
- 346528; Provide Guidance for the Use of Intermittent Loads; Revision 0
- 353125; Removal of Disc From Valve 1DG032; Revision 0
- 353657; Isolation of Metering to Common 141Y/142Y and 241Y/242Y Safety Related Buses; Revision 0

Operability Evaluations:
- OE 02-008; Plugging of Unit 2 Drywell Floor Drain Effects on Leak Detection Instrumentation; Revision 0
- OE 05-001; Minimum 6-inch Physical Separation in Division 1 & 2 CTs; Revision 0

Procedures:
- CC-AA-308; Control and Tracking of Electrical Load Changes; Revision 4
- LES-DC-103A; Division I Battery Charger Capacity Test; Revision 11
- LOR-1PM13J-A301; Drywell Floor Drain Sump Level Hi, Hi Hi, or Pump Start Failure; Revision 4
- LOS-AA-S101; Unit 1 Shiftly Surveillence; Revision 28

Temporary Configuration Change:
- 353167; Install Alternate Method of Determining DWFDS Flow Rate; 1/24/05

1EP2 Alert and Notification System (ANS) Testing

Procedures:
- EP-AA-125-1004; Emergency Response Facilities and Equipment Performance Indicator Guidance; Revision 3

LaSalle County Station Design Study for Total EPZ Siren Coverage; January 2002

LaSalle County Station Off-Site Siren Test Plan; Revision 4; December 2002

Warning System Maintenance and Operational Reports for LaSalle County Station:
- January 8, 2003 through February 28, 2003
- February 11, 2004 through March 2, 2004

Siren Operations Manual - LaSalle County; February 28, 2003

Exelon Semi-Annual Siren Reports For LaSalle County Station:
- January 1, 2003 through June 30, 2003
- July 1, 2003 through December 31, 2003
- January 1, 2004 through June 30, 2004

Issue Reports:
- 206404; Review of Semi-Annual, Non-Scheduled Maintenance Report for First Half of 2003
- 208758; Review of Semi-Annual, Non-Scheduled Maintenance Report for Second Half of 2003

1EP3 Emergency Response Organization (ERO) Augmentation Testing

Procedures:
- EP-AA-112-100; Control Room Operations; Revision 7
- EP-AA-112-100-F-01; Shift Emergency Director Checklist; Revision B
- EP-AA-112-100-F-06; Midwest ERO Augmentation; Revision C
- EP-AA-122-1001; Attachment 2; Conduct of Call-In Augmentation Drills; Revision 3

LaSalle County Station ERO Off-Hours, Unannounced, Off-Hours Augmentation Call-In Drill Records; April 2004 through January 2005

LaSalle Station ERO Roster; Teams A through D and Back-ups; March 2005

Random Sample of 30 LaSalle County Station ERO Members' EP Training Records

Issue Reports:
- 217626; Paging Concerns in April 2004 Augmentation Drill
- 221122; Paging Concerns in May 2004 Augmentation Drill
- 236587; Three On-call ERO Did Not Receive Page in July 2004 Drill
- 262750; Paging Concerns in October 2004 Augmentation Drill
- 275140; Two ERO Members Did Not Receive Page in November 2004 Drill
- 282734; Four ERO Members Did Not Receive Page in December 2004 Drill
- 292460; Three ERO Members Did Not Receive Page in January 2005 Drill
- 262750; Evaluation of ERO Response Problems During Monthly Augmentation Drills

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies

Procedures:
- EP-AA-122; Drills and Exercises; Revision 4
- EP-AA-122-1001; Drill Development, Conduct, and Evaluation; Revision 4

Internal Memorandums:
- Mini-Drill Findings and Observation Report for Four Drills in August 2003; September 2, 2003
- October 2003 Mini-Drill Findings and Observation Report; October 24, 2003
- LaSalle County Station 2003 Medical Drill Findings and Observation Report; January 5, 2004
- LaSalle 2004 NRC Graded Exercise Findings and Observation Report; April 9, 2004
- May 19 and June 2, 2004 Mini-Drills Findings and Observation Report; June 3, 2004
- LaSalle County Station June 28, 2004 Unusual Event Critique Report; July 26, 2004
- July 29 and August 5, 2004 Mini-Drills Findings and Observation Report; August 11, 2004
- December 9 and December 16, 2004 Mini-Drills Findings and Observation Report; December 30, 2004
- LaSalle County Station 2004 Medical and Health Physics Drill Findings and Observation Report; December 20, 2004

Nuclear Oversight Reports:
- Emergency Preparedness 50.54(t) and Meteorology Audit Report LAS-04-03; Performed on April 12 through 16, 2004; April 22, 2004
- Objective Evidence Report LS-04-3Q; ERO Staffing and Awareness of Fitness-for-Duty Expectations
- Objective Evidence Report LS-04-4Q; Observations of Two Mini-Drills and Medical Drill in December 2004

Root Cause Investigation Report; Emergency Plan Radiation Protection On-Shift Requirement Not Met Due to Lapsed Radiation Protection Qualifications of Chemistry Technicians; December 3, 2004

Issue Reports:
- 178665; NOS Observations of December 2003 Medical Drill
- 190290; NOS Observations During February 2004 Drill and March 2004 Exercise
- 202751; February 2004 Drill Scenario Validation Concerns
- 207883; Three Concerns on Performance of In-Plant Teams' Controllers During March 2004 Exercise
- 207887; March 2004 Exercise Scenario Development and Control Weaknesses
- 207890; Warning Onsite Personnel Objective Failed During March 2004 Exercise
- 209239; Re-assess Seismic Monitor Set Point Value in Emergency Action Level HU-4
- 214187; Slow Decision Making to Authorize Potassium Iodide to Affected On-site Personnel During March 2004 Exercise
- 214200; Operations Support Center ERO Performance Concerns During March 2004 Exercise
- 215285; Several Emergency Plan Elements Not Tested in Five-Year Period
- 215362; Some Recreational Facilities Within the EPZ Did Not Have Posted Emergency Information
- 216385; No Actions Planned for ERO Pagers' "Dead Zones"
- 232858; Notification Performance Improvement Opportunities from June 2004 Actual Unusual Event Response
- 241268; Resident Inspector Noted Failure to Consider Applicability of a Heat Stress Procedure During a July 2004 Drill

- 257638; On-Shift ERO Staffing Concern - Training of Chemistry Technicians Versus Training Of Radiation Protection Technicians
- 264105; NOS Concern on Critique When 2004 Medical Drill was Suspended
- 273813; Technical Support Center's Particulate, Iodine, and Noble Gas Monitor is Out of Calibration and Back-up Monitor Not Adequate

Training Request 04-402; Additional Training on Notification Timeliness

NRC Event Report 40845; Unusual Event Declared Due to Earthquake Registered at LaSalle County Station

Required Reading Packages:
- ERO Package on February 2004 Drill and March 2004 Exercise
- Shift Managers Package on Warning Onsite Personnel Concerns During March 2004 Exercise
- ERO Package on Operations Support Center Staff's Performance Concerns During March 2004 Exercise

Corporate Action Requests:
- 5040EP; Corporate EP Staff Revise ERO Training Procedure to Increase Level of Detail on ERO Training of Radiation Protection Versus Chemistry Technicians
- 8007EP; Corporate EP Staff Assess Process to Determine Qualification Requirements of ERO Members Whose ERO Training Includes Accredited Training Performed by Other Departments

2OS1 Access Control to Radiologically Significant Areas

Access Control to Radiologically Significant Areas and Occupational Exposure Control Effective Performance Indicator; September 30, 2005

Issue Reports:
- 261792; Access Control Focused Area Self-Assessment; 10/8/2004
- 282460; TLD Run Through X-Ray Machine; 12/13/2004
- 291904; Exceeded Dose Allotted for Coil Cleaning; 1/19/2005
- 293751; Unexpected High Dose-Rate on Radwaste Container; 1/24/2005
- 294919; Venture Scaffold Carpenters Contaminated; 1/25/2005
- 297958 Venture Carpenter – Electronic Dosimeter Dose Rate Alarm; 2/4/2005
- 298702; Radworker Human Performance Issue; 2/7/2005
- 299284; Dose Rate Alarm Received While Hanging Lead in 2B RHR; 2/14/2005
- 299670; (NOS ID) Radiation Protection Improper Posting on the Turbine Deck; 2/9/2005
- 299705; Failure to Obtain Thermoluminescent Detector Prior to Working in Radiologically Controlled Area; 2/9/2005
- 299750; Dose Rate Alarm Received During Shielding Installation; 2/9/2005
- 300861; Electronic Dosimeter Dose Rate Alarms in 678 Turbine Building Main Steam Tunnel; 2/13/2005
- 299763; Dose Rate Alarm Received During Shielding Installation; 2/9/2005
- 301189; Unexpected Dose Rate Alarm – Venture Pipefitter; 2/19/2005
- 301225; Contaminated Area Reach-In – Venture Worker; 2/19/2005

- 301798; Prompt Investigation Report of PN Services Workers Cut Vent Hose on Refuel Floor; 2/15/2005

Procedures:
- MA-AA-716-010; Maintenance Planning; Revision 4
- MA-MW-716-010-1000; Passport Work Planning Manual; Revision 4
- RP-AA-461; Radiological Controls for Contaminated Water Diving Operations; Revision 0

2OS2 As Low As Is Reasonably Achievable Planning And Controls (ALARA)

Issue Reports:
- 300541; RQP Hold Released By Non-Radiation Protection Person; 2/11/2005
- 300710; Work Order RQP Hold Bypassed; 2/12/2005
- 300730; LaSalle Permitting Low Standards of Work, Ineffective Corrective Actions; 2/12/2005

Procedures:
- RP-AA-376-1001; Radiological Posting, Labeling, and Marking Standard; Revision 2
- RP-AA-401; Operational ALARA Planning and Controls; Revision 4

Radiation Work Permits:
- 10004000; L2R10 Temporary Shielding in the Drywell; Revision 2
- 10004003; L2R10 Scaffold Activities in the Drywell; Revision 0
- 10004016; L2R10 CRD Pull and Put; Revision 2
- 10004057; L2R10 Unit 2 Reactor Suppression Pool Activities and Support; Revision 0
- 10004088; Unit 2 Reactor Vessel Disassembly and Reassembly; Revision 1
- 10004792; L2R10 Chemical Decon Drywell Work/Unit 2 RB 774'; Revision 0

4OA1 Performance Indicator Verification

Procedures:
- EP-AA-125-1002; ERO Performance; Revision 3
- EP-AA-125-1003; ERO Readiness; Revision 4
- EP-AA-125-1004; Emergency Response Facilities and Equipment; Revision 3
- LS-AA-2110; Monthly Data Elements for NRC ERO Drill Participation; January 2004 through December 2004; Revision 6
- LS-AA-2120; Monthly Data Elements for NRC Drill and Exercise Performance; January 2004 through December 2004; Revision 4
- LS-AA-2130; Monthly Data Elements for NRC ANS Reliability; January 2004 through December 2004; Revision 4

Siren Reports:
- Daily Reports; January 1, 2004 through December 31, 2004
- Monthly Operability Reports; January 2004 through December 2004

Required Reading Package; Protective Action Recommendation Development; dated June 2004

Issue Reports:
- 241955; Failure to Classify an Alert During August 2004 Drill
- 242469; Inaccurate Emergency Class on Notification Form During August Drill
- 242025; Incorrect Protective Action Recommendation Developed During a Drill
- 249574; Adverse Trend in DEP Performance Indicator in Fourth Quarter 2004
- 283475; Failure to Classify an Alert 15 Minutes During December 9, 2004, Drill
- 283601; Inaccurate Notification Form Completed During December 16, 2004, Drill
- 306946; NOS Identified Minor Error with Reported DEP PI Opportunities for Fourth Quarter 2004

4OA2 Identification and Resolution of Problems

Procedures:
- CC-AA-201; Plant Barrier Control Program; Revision 5
- OP-MW-201-004; Fire Prevention for Hot Work; Revision 0
- OP-MW-201-007; Fire Protection System Impairment Control; Revision 3
- OP-AA-201-001; Fire Marshal Tours; Revision 2
- OP-AA-201-008; Pre-Fire Plans; Revision 1
- OP-AA-201-009; Control of Transient Combustible Material; Revision 4

Issue Reports:
- 280218; 2A Diesel Generator Trip on Reverse Power; 12/07/2005
- 302209; Small Fire in Unit 2 Reactor Building – 694’ Elevation; 2/16/2005
- 302447; Near Miss – Fire Extinguisher Malfunction; 2/16/2005
- 304516; (NRC Identified) RHR Keep Fill Modification Fire Protection Awareness; 2/23/2005

4OA3 Event Follow-up

Corporate RCR 299641; Single Failure Vulnerability of Safety Related Division 1 & 2 Protective Relay Circuitry Root Cause Analysis; 3/8/2005

RA05-25; License Condition 2.F(a) Report: Exceeding License Condition 2.C(1); 3/9/2005

Issue Reports:
- 297076; Vulnerability of Division 1 & 2 Protective Relay Circuitry; 2/4/2005
- 299188; Lack of Minimum 6-inch Physical Separation in Division 1 & 2 CTs; 2/8/2005
- 304613; Controller Failed High; 2/23/2005
- 304789; Failure of 1HK-RR023 Results in Unit 1 Operation Greater Than 100 % RTP; 2/23/2005
- 305612; Evaluation of Operations Crew Performance – RR FCV Failure; 2/25/2005
- 307523; Problem with Re-Flash Function for SPDS Button on PPC; 3/2/2005
- 307654; Evaluate LOA-RR-101(102) for Possible Revision; 3/2/2005
- 307657; U1 PPC Alarm Program May Prevent Audible Alarm; 3/2/2005
- 307659; U2 PPC Alarm Program May Prevent Audible Alarm; 3/2/2005

Operability Evaluation:
- OE 05-001; Minimum 6-inch Physical Separation in Division 1 & 2 CTs; Revision 0

Engineering Change:
- EC 353657; Isolation of Metering to Common 141Y/142Y and 241Y/242Y Safety Related Buses; Revision 0

LIST OF ACRONYMS USED

ACE	Apparent Cause Evaluation
ALARA	As-Low-As-Is-Reasonably-Achievable
ANS	Alert and Notification System
APRM	Average Power Range Monitor
ARM	Area Radiation Monitor
ASME	American Society of Mechanical Engineers
CAP	Corrective Action Program
CAR	Corrective Action Request
CCA	Common Cause Analysis
CFR	Code of Federal Regulations
CIV	Containment Isolation Valves
CR	Condition Report
CRD	Control Rod Drive
CRS	Control Room Supervisor
CSCS	Core Standby Cooling System
CT	Current Transformer
CW	Circulating Water
CY	Calendar Year
DC	Direct Current
DG	Diesel Generator
DGN	Diesel Generators
DRP	Division of Reactor Projects
DW	Drywell
ECCS	Emergency Core Cooling System
ED	Electronic Dosimeter
EDG	Emergency Diesel Generator
EP	Emergency Preparedness
EPZ	Emergency Preparedness Planning Zone
ERO	Emergency Response Organization
ES	Engineered Safeguards
FC	Fuel Pool Cooling
FCV	Flow Control Valve
HEPA	High Efficiency Particulate Air
HRA	High Radiation Area
I&C	Instrumentation and Controls
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Inspection Report or Issue Report
ISI	Inservice Inspection
IST	Inservice Test
kV	Kilovolt
kW	Kilowatts
kVAR	Kilovolts-Amperes-Reactive
LLRT	Local Leak Rate Testing
LPCS	Low Pressure Core Spray
LOCA	Loss of Coolant Accident
mrem	Millirem

msec	Millesecond
MWth	Megawatts Thermal
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NLO	Non-Licensed Operator
NRC	U.S. Nuclear Regulatory Commission
NSO	Nuclear Station Operator
OWA	Operator Workaround
PI	Performance Indicator
PI&R	Problem Identification and Resolution
PRM	Process Radiation Monitors
RA	Required Actions
RCA	Radiologically Controlled Area
RCIC	Reactor Core Isolation Cooling
RCR	Root Cause Report
RCR	Root Cause Review
RFO	Refueling Outage
RHR	Residual Heat Removal
RHRSW	Residual Heat Removal Service Water
RO	Reactor Operator
RP	Radiation Protection
RPS	Radiation Protection Specialist
RPS	Reactor Protection System
RPT	Radiation Protection Technician
RR	Reactor Recirculation
RWCU	Reactor Water Cleanup
RWP	Radiation Work Permit
SAT	Station Auxiliary Transformer
SBGT	Standby Gas Treatment
SBLC	Standby Liquid Control
SDP	Significance Determination Process
SRA	Senior Reactor Analyst
SRO	Senior Reactor Operator
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
Vac	Volts Alternating Current
Vdc	Volts Direct Current
VY	Ventilation System