UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
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LISLE, IL 60532-4352

July 18, 2013

Mr. Michael J. Pacilio
Senior Vice President, Exelon Generation Company, LLC
President and Chief Nuclear Officer, Exelon Nuclear
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: LASALLE COUNTY STATION, UNITS 1 AND 2 - NRC SPECIAL INSPECTION TEAM (SIT) INSPECTION REPORT 05000373/2013009; 05000374/2013009

Dear Mr. Pacilio:

On June 3, 2013, the U.S. Nuclear Regulatory Commission (NRC) completed a special inspection at your LaSalle County Station, Units 1 and 2. The enclosed inspection report documents the inspection results, which were discussed on June 3 with Mr. Harold Vinyard, the plant manager, and other members of your staff.

The inspection started on April 22, 2013, in accordance with NRC Management Directive 8.3, "NRC Incident Investigation Program," and Inspection Manual Chapter 0309, "Reactive Inspection Decision Basis for Reactors," based on the initial deterministic criteria evaluation made by the NRC.

The inspection reviewed the circumstances surrounding the dual-unit automatic reactor scram and loss of offsite power on April 17, 2013. The loss of offsite power occurred when the breakers in the 345-kiloVolt switchyard opened, shortly following a lightning strike in the adjacent 138-kiloVolt switchyard. The inspection examined activities conducted under your license as they relate 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, conducted field walkdowns, and interviewed personnel. The special inspection charter (Attachment 2 of the enclosure) provided the basis and focus areas for the inspection.

Based on the results of this inspection, one NRC-identified finding of very low safety significance (Green) was identified during this inspection. This finding was determined to involve a traditional enforcement Severity Level IV violation of NRC requirements. The NRC is treating this violation as a non-cited violation (NCV), consist with Section 2.3.2 of the Enforcement Policy. Also, your root cause evaluation of the loss of offsite power was completed after the conclusion of our inspection and, consequently, we will complete our review of this evaluation as part of a future inspection. You will be notified of the results of our review.

If you contest this non-cited violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial to the Nuclear Regulatory Commission, ATTN.: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, Region III; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at LaSalle County Station.

If you disagree with the cross-cutting aspect assignment in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region III, and the NRC Resident Inspector at LaSalle County Station.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room and from the Publicly Available Records System (PARS) component of NRC's document system, Agencywide Documents Access and Management System (ADAMS). ADAMS is accessible from the NRC Website at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Steven Reynolds, Director
Division of Reactor Projects

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

Enclosure: Inspection Report 05000373/2013009; 05000374/2013009;
w/Attachments:
1. Supplemental Information
2. Memo to Kemker
3. LaSalle Timeline

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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:	05000373/2013009; 05000374/2013009
Licensee:	Exelon Generation Company, LLC
Facility:	LaSalle County Station, Units 1 and 2
Location:	Marseilles, IL
Dates:	April 22, 2013 – June 3, 2013
Inspectors:	B. Kemker, Senior Resident Inspector, Clinton Station (Lead) M. Munir, Reactor Inspector K. Carrington, Reactor Engineer R. Jickling, Senior Emergency Preparedness Inspector
Approved by:	M. Kunowski, Chief Branch 5 Division of Reactor Projects

Enclosure

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3. LASALLE DUAL UNIT SCRAM AND LOOP TIMELINE

SUMMARY OF FINDINGS

Inspection Report (IR) 05000373/2013009, 05000374/2013009; 04/22/2013 – 06/03/2013; LaSalle County Station, Units 1 and 2; Inspection Procedure (IP) 93812, Special Inspection

This report covers a 5-day period (April 22 - 26, 2012) of onsite inspection and subsequent offsite inspection activities. A team of one senior resident inspector and three regional inspectors conducted this special inspection. The inspectors identified one Severity Level IV non-cited violation. The significance of inspection findings is indicated by their color (i.e., greater-than-Green, Green, White, Yellow, Red) and determined using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process," dated June 2, 2011. Cross-cutting aspects are determined using IMC 0310, "Components Within the Cross-Cutting Areas," dated October 28, 2011. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4.

NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

Severity Level IV. The inspectors identified a finding of very low safety significance with an associated Severity Level IV non-cited violation of the NRC's reporting requirements in 10 CFR 50.72(a)(1), "Immediate Notification Requirements for Operating Nuclear Power Reactors." The licensee failed to make a required 8-hour non-emergency notification call to the NRC Operations Center after discovery of a condition that could have prevented fulfillment of the safety function of the low pressure core spray (LPCS) system. The licensee entered this issue into its corrective action program (CAP) for evaluation and made an appropriate notification call to the NRC Operations Center.

This finding was of more than minor significance because the NRC relies on licensees to identify and report conditions or events meeting the criteria specified in the Technical Specifications and the regulations in order to perform its regulatory function. Because this issue affected the NRC's ability to perform its regulatory function, the inspectors evaluated it using the traditional enforcement process and assessed the significance of the underlying issue using the Significance Determination Process (SDP). The underlying technical issue (i.e., an inoperable LPCS system) was determined to be of very low safety significance using the SDP. Consistent with the guidance in Section 6.9, Paragraph d.9, of the NRC Enforcement Policy, the violation associated with this finding was determined to be a Severity Level IV Violation. This finding affected the cross-cutting area of problem identification and resolution. Specifically, the licensee did not implement and institutionalize operating experience from a similar event reported at another licensee's facility while evaluating the reportability of the inoperable single train safety system with respect to the 10 CFR 50.72 reporting requirements (P.2(b)). (Section 4OA5.5.b.(1))

REPORT DETAILS

Summary of the Event

April 17, 2003

At 2:59 p.m. (Central Standard Time), LaSalle County Station Units 1 and 2 automatically scrammed from 100 percent power, in conjunction with a loss of offsite power (LOOP). The loss of offsite power occurred when the breakers in the main 345-kV switchyard opened, shortly following a lightning strike in the adjacent 138-kiloVolt (kV) switchyard during a thunderstorm. The station's five emergency diesel generators (EDGs) immediately started, successfully loaded onto their respective safety-related buses, and began supplying power to the buses to support operation of essential loads, as expected. The licensee declared a Notification of Unusual Event (NOUE) at 3:11 p.m. because of the LOOP. The licensee was able to restore offsite power and exited the NOUE at 8:14 a.m. the following day, April 18.

Following the scrams of both reactors, plant safety-related equipment responded as expected, with two exceptions. The Unit 2 C (2C) residual heat removal (RHR) pump failed to start following an engineered safety features (ESF) actuation signal based on high drywell pressure, and the Unit 1 low pressure core spray (LPCS) system injection valve (1E21-F005) failed to open when control room operators attempted to manually open the valve using the control switch. Both failures had no significant effect on the ability of operators to respond to the event. In addition, during the NRC's monitoring of the licensee's response to the event and subsequently, questions arose from the NRC staff about the performance of other safety- and nonsafety-related equipment.

This event involved significant unexpected system interactions. Specifically, a lightning strike to a component of the 138-kV electrical system in the switchyard resulted in the opening of all breakers in the 345-kV electrical system ring bus and the loss of offsite power to both LaSalle units. Section 8.2.3.2, "Adequacy of Offsite Power," and Section 8.1.2.5, "Unit Non-Class 1E DC [direct current] System" of the LaSalle County Station Updated Final Safety Analysis Report (UFSAR) indicate that this type of LOOP should not have occurred.

Inspection Scope

Based on the deterministic and conditional risk criteria specified in Management Directive 8.3, "NRC Incident Investigation Program," a special inspection was initiated in accordance with NRC Inspection Procedure 93812, "Special Inspection Team." The special inspection charter, dated April 26, 2013, is included as Attachment 2. The team reviewed technical and design documents, control room logs, plant process computer data and plots, procedures, maintenance records, and CAP documents; interviewed station personnel; and performed walk downs of plant equipment. A list of documents reviewed is provided in Attachment 1.

4. OTHER ACTIVITIES

4OA5 Other Activities – Special Inspection (93812)

In accordance with the charter for this inspection (Attachment 2), the following items were reviewed.

.1 Identify a time-line for the event. Include relevant and major plant conditions, system line-ups, and operator actions.

a. Inspection Scope

The inspectors reviewed control room logs, plant process computer data and plots, CAP documents, and interviewed plant personnel for information related to the sequence of events.

b. Findings and Observations

No findings were identified. A timeline of the event is contained in Attachment 3.

.2 Review plant data and records to confirm the adequacy of the licensee's assessment of the cause of the scram of the reactors.

a. Inspection Scope

The inspectors reviewed control room logs, CAP documents, plant process computer data and plots, and interviewed members of the licensee's staff.

b. Findings and Observations

No findings were identified.

The Unit 1 and 2 reactors scrammed due to the loss of the 345-kV switchyard (i.e., the opening of switchyard breakers). The reactor protection system actuation for each unit was due to a main generator trip caused by turbine control valve fast closures. As discussed below in Section 4OA5.3, the LOOP (both the 345-kV and 138-kV switchyards) was caused by a series of events initiated by a lightning strike in the 138-kV switchyard.

The licensee's root cause evaluation was not yet completed at the conclusion of the inspection.

.3 Review the circumstances of the dual-unit loss of offsite power following the lightning strike in the plant switchyard. Include a review of relevant portions of the UFSAR that discuss the switchyard.

a. Inspection Scope

The inspectors reviewed the licensee's preliminary assessment of what caused the dual-unit LOOP resulting in the dual-unit reactor scrams at LaSalle County Station. The inspectors also reviewed the design basis of the switchyard as described in the UFSAR and interviewed members of the licensee's staff.

b. Findings and Observations

No findings were identified.

The LaSalle switchyard consists of a 345-kV section (or switchyard) with 4 offsite lines coming in and an adjacent 138-kV section (or switchyard) with 2 offsite lines coming in. The 138-kV switchyard was installed to support original plant construction and now supplies several nonsafety-related loads. On April 17, 2013, at 2:57 p.m., 138-kV line L0112 (Transmission Sub-Station (TSS) 105 Kickapoo – Station (STA) 1 LaSalle) experienced a lightning-related phase-to-ground fault on a piece of equipment in the 138-kV switchyard. The fault was properly cleared at both ends in 4 cycles; however, the lightning strike and resultant fault elevated the local ground grid in the 138-kV switchyard sufficiently to affect the switchyard System 2 direct current (DC) battery system, located in the relay house in the adjacent 345-kV switchyard, with a voltage transient. Visual inspection revealed evidence of a flashover point at the Transformer 81 138-kV breaker's incoming DC knife-blade terminal block point. The transient on the battery system ultimately caused all breakers on the 345-kV system to open. It should be noted that the control power for both the 138-kV and 345-kV switchyard breakers was supplied by two common redundant battery systems located in the switchyard relay house. The System 2 DC battery system was in service at the time of the event supplying control power to both the 138-kV and 345-kV switchyard breakers. Two minutes after the initial fault, 138-kV line L0112 experienced another phase-to-ground fault at the STA 1 terminal and the TSS 105 breaker tripped in 4.5 cycles and remained locked out. At STA 1, the resultant fault elevated the local ground grid in the 138-kV switchyard sufficiently to affect the System 2 battery system with a voltage transient through the Transformer 81 fuse block flash point. The fault transient caused damage to solid state/electronic devices utilizing the System 2 DC system. During a walk down of the switchyard, the licensee found damage to the 'C' phase capacitively coupled voltage transformer west of the L0112 bushing, with collateral damage to disconnects and the oil circuit breaker L0112 'B' bushing.

The plant effect was a dual-unit LOOP resulting in a dual-unit scram, with all five EDGs loading onto the safety busses. The foregoing description was the licensee's preliminary assessment of the event that took place. At the end of this inspection, the licensee was performing its root cause evaluation. The inspectors reviewed the preliminary assessment and the design basis of the switchyard as described in the UFSAR. The inspectors noted that Section 8.2.3.2, "Adequacy of Offsite Power," of the UFSAR stated, in part, that: "The switchyard arrangement is such that offsite power to both units cannot be lost due to any single failure." Additionally, UFSAR Section 8.1.2.5, "Unit Non-Class 1E DC System," stated, in part, that: "The design of the protective relay circuits for the 345-kV oil circuit breakers and the 345-kV transmission lines is such that the loss of either battery or the loss of both batteries and associated feeder cables will not cause the loss of offsite power sources." Whether the series of events in the LaSalle switchyards that led to the dual-unit LOOP stemmed from a single failure or more than one failure, and whether the design of the switchyards meets regulatory requirements remain open questions. The issue will be treated as an Unresolved Item **(URI 05000373/2013009-01; 05000374/2013009-01, Review of the Loss of Offsite Power Event Root Cause Evaluation and Switchyard Design Basis)** pending completion of the licensee's root cause evaluation and resolution of open questions on the switchyard design basis.

.4 Review the licensee's evaluation of the failure of the Unit 2 C RHR pump to start.

a. Inspection Scope

To assess the failure of the Unit 2 C (2C) RHR pump to start, the inspectors reviewed the pertinent electrical schematic diagrams associated with the pump, schematic diagrams of the control circuit of the 4.16-kV circuit breaker feeding the pump, other pertinent vendor data relating to breaker closing spring charging time, and interviewed members of the licensee's staff.

b. Findings and Observations

No findings were identified. However, weaknesses in licensed operator knowledge of the low pressure coolant injection (LPCI) system response (in particular, the 2C RHR pump) to a LOOP followed by an ESF actuation signal were apparent during the event and warrant additional attention by the licensee to improve through training.

Background Information

On April 17, at about 4:27 p.m., the 2C RHR pump failed to start from an ESF actuation signal based on high drywell pressure after the deenergizing/reenergizing of 4.16-kV safety bus 242Y during the event.

Emergency core cooling system (ECCS) pump start logic includes an anti-pumping circuit to prevent the chattering of the pump's power supply breaker. The anti-pumping circuit contains a contact (LSb) whose actuation is based on the charge of the breaker charging coils. This contact will remain closed, therefore energizing a pump lockout relay (relay y) until the breaker charging springs are fully charged, roughly equal to three to five seconds. This circuit requires a reset of the pump actuation signal after the springs are fully charged in order for the pump lockout relay to de-energize. If the breaker were to reopen after closure, as during load shedding of an EDG, and ample time (three to five seconds) is not allowed for the charging springs to charge, the seal-in feature of the anti-pumping circuit (contact Ya whose position is determined by relay y) will prevent any further successful attempts of pump actuation.

Upon the ESF actuation signal, the 2B and 2C RHR pump breakers closed, starting the 2B/2C LPCI system trains. Load shedding of the 2A EDG commenced per design. 1.345 seconds following the ESF signal, both the 2B and 2C RHR pumps tripped due to an under-voltage condition caused by the load shedding, hence opening both pumps' breakers. The under-voltage condition cleared 0.157 seconds later when the 2A EDG output breaker reclosed onto the 242Y bus. Once the 242Y bus was reenergized, the 2C pump auto-start relay (K21) reenergized, giving a second 2B/2C LPCI system train actuation signal (0.079 seconds later). The total amount of time from the first 2C RHR pump breaker closure to the second attempted closure (K21 relay energizing) was equal to 1.606 seconds. This was not sufficient time for the breaker charging springs to fully charge. The pump breaker anti-pumping circuit (relay y) was then left energized, which prevented the second closure of the 2C RHR pump breaker. The system worked per design.

The Unit 2 control room operators, however, did not understand how the pump breaker would indicate an apparent start failure due to the simultaneous signals and, therefore, they concluded that the 2C RHR pump had failed to start. Since it was not needed at the time for LPCI system injection, operators declared the pump inoperable, put the pump's control switch in pull-to-lock, and made no attempt to immediately restart it. Subsequently, during troubleshooting, the pump was able to start when operators manually reset the logic with the pump's control switch and then started the pump.

Conclusion

The inspectors reviewed the electrical schematic diagrams for the 2C RHR pump and schematic diagrams of the internal control circuit of the 4.16-kV circuit breaker and determined that the ECCS systems were designed for a simultaneous LOOP and ESF actuation signal, not a LOOP followed by a loss of coolant accident (LOCA).

The licensee wrote action request (AR) 01504675 to document the results of its troubleshooting efforts into the 2C RHR pump's unexpected failure to start from an ESF actuation following the load shedding due to the EDG bus under-voltage condition. The AR captured the licensed operator knowledge weaknesses discussed above and identified appropriate corrective actions, including procedure changes and operator training. In addition, in response to the inspectors' questions regarding this and other apparent licensed operator knowledge weaknesses during the event, the licensee wrote AR 01522619 and initiated a common cause evaluation to identify appropriate corrective actions, including operator training.

.5 Review the licensee's evaluation of the failure of the Unit 1 LPCS injection valve (1E21-F005) to open.

a. Inspection Scope

The inspectors reviewed control room logs, CAP documents, pertinent electrical schematic diagrams, the associated maintenance work order relating to the failure of the Unit 1 LPCS injection valve to open, and interviewed members of the licensee's staff.

b. Findings and Observations

(1) Failure to Satisfy 10 CFR 50.72 Reporting Requirements

Introduction: The inspectors identified a finding of very low safety significance (Green) with an associated Severity Level IV non-cited violation of the NRC's reporting requirements in 10 CFR 50.72(a)(1), "Immediate Notification Requirements for Operating Nuclear Power Reactors." The licensee failed to make a required 8-hour non-emergency notification call to the NRC Operations Center after discovery of a condition that could have prevented fulfillment of the safety function of the LPCS system.

Discussion: On April 18, at about 1:00 p.m., with Unit 1 operating in Mode 3 (Hot Shutdown), control room operators were attempting to raise Unit 1 reactor vessel level with the LPCS system when they discovered that the LPCS injection valve (1E21-F005) failed to open when the valve control switch was held in the "open" position. Operators were transferring reactor vessel level control from the reactor core isolation cooling (RCIC) system to the LPCS system as the unit was being depressurized for entry into Mode 4 (Cold Shutdown) following the LOOP on April 17. Operators started the LPCS system at 12:59 p.m. and subsequently attempted to open 1E21-F005, but the valve did not open. The licensee declared the LPCS system inoperable at 1:40 p.m. The licensee replaced the control switch, completed post-maintenance testing, and restored the LPCS system to an operable status on April 20 at 4:20 a.m.

The inspectors noted that the licensee had not considered this to be a loss of safety function for the single train system and had not reported the event in accordance with 10 CFR 50.72, “Immediate Notification Requirements for Operating Nuclear Power Reactors,” Paragraph (b)(3)(v)(D), as an event or condition that at the time of discovery could have prevented the fulfillment of the safety function of structures or systems that are needed to mitigate the consequences of an accident. The inspectors reviewed the guidance in NUREG 1022, “Event Reporting Guidelines 10 CFR 50.72 and 50.73,” Revision 2, and questioned the licensee’s initial conclusion that inoperability of the LPCS system was not reportable as a loss of safety function because it was redundant to other ECCS. The inspectors referred to NUREG-1022, and noted the following under Section 3.2.7, “Event or Condition That Could Have Prevented Fulfillment of a Safety Function”:

- The intent of these criteria is to capture those events when there would have been a failure of a safety system to properly complete a safety function.
- These criteria cover an event or condition where structures, components, or trains of a safety system could have failed to perform their intended function because of: […] equipment failures.
- The event must be reported regardless of whether or not an alternate safety system could have been used to perform the safety function.
- There are a limited number of single train systems that perform safety functions. For such systems, loss of the single train would prevent the fulfillment of the safety function of that system and, therefore, is reportable.

In response to the inspectors’ questions, the licensee prepared a position paper that summarized its position that the LPCS system was not a single train system for reporting purposes but a redundant system to both the RHR and the high pressure core spray (HPCS) systems. Therefore, the reporting requirement would not be met due to the previously mentioned systems being able to provide the appropriate safety function. The licensee’s position paper was presented to the inspectors on April 23. The inspectors reviewed the UFSAR and consulted with NRC regional and headquarters staff to determine the treatment of the LPCS system for reporting purposes. Subsequently, the inspectors concluded that the LPCS system was a single train system as described in the UFSAR and that the failure of the injection valve to open was a reportable condition. Because the condition existed (i.e., it was occurring) at the time of discovery on April 18, the inspectors concluded that the 10 CFR 50.72(b)(3) criterion for an 8-hour notification call to the NRC was met and the licensee should have made the appropriate notification call. The licensee subsequently submitted the required report (Event Notification 48966) to the Headquarters Operations Officer on April 25.

Analysis: The inspectors determined that the licensee’s failure to report this issue as a condition that could have prevented the fulfillment of the safety function of structures or systems needed to mitigate the consequences of an accident was a licensee performance deficiency warranting a significance evaluation. Consistent with the guidance in Inspection Manual Chapter (IMC) 0612, “Power Reactor Inspection Reports, Appendix B, “Issue Screening,” dated September 7, 2012, because this violation of the NRC’s reporting requirements affected the NRC's ability to perform its regulatory function, the inspectors evaluated the violation using the traditional enforcement process in accordance with the NRC Enforcement Policy and assessed the significance of the underlying issue (i.e., an inoperable LPCS system) using the Significance Determination Process (SDP). The inspectors reviewed the examples of minor issues in IMC 0612, "Power Reactor Inspection Reports," Appendix E, "Examples of Minor Issues," dated August 11, 2009, and found no examples related to this issue. The inspectors determined that this finding was of more than minor significance because the NRC relies on licensees to identify and report conditions or events meeting the criteria specified in the Technical Specifications (TSs) and the regulations in order to perform its regulatory function. The inspectors performed a significance screening of the underlying issue using the guidance provided in IMC 0609, "Significance Determination Process," Appendix A, "The SDP for Findings At-Power," dated June 19, 2012. In accordance with Exhibit 2, "Mitigating Systems Screening Questions," the inspectors determined that this finding would require a detailed risk evaluation because it represented an actual loss of safety function of a system.

The Region III Senior Reactor Analyst completed a detailed risk evaluation of the LPCS valve failure using the NRC's Standardized Plant Analysis Risk model for LaSalle County Station, Version 8.21. The exposure period was assumed to be 1 year. The estimated change in core damage frequency was less than 1E-7/year, which represents a finding of very low safety significance (Green). The dominant sequence was a loss of 4.16-kV bus 242Y, successful operation of the RCIC system, followed by failure of the suppression pool cooling and low pressure injection systems.

Consistent with the guidance in Section 6.9, Paragraph d.9, of the NRC Enforcement Policy, the violation associated with this finding was determined to be a Severity Level IV Violation.

The inspectors concluded that this finding affected the cross-cutting area of problem identification and resolution. Specifically, the licensee did not implement and institutionalize operating experience from a similar event reported at another licensee's facility while evaluating the reportability of the inoperable single train safety system with respect to the 10 CFR 50.72 reporting requirements (P.2(b)).

Enforcement: 10 CFR 50.72(a)(1)(ii) requires, in part, that the licensee notify the NRC Operations Center via the Emergency Notification System of those non-emergency events specified in Paragraph (b) that occurred within three years of the date of discovery. 10 CFR 50.72(b)(3) requires, in part, that the licensee notify the NRC as soon as practical and in all cases within eight hours of the occurrence of any of the applicable conditions. 10 CFR 50.72(b)(3)(v)(D) required, in part, that the licensee report any event or condition that at the time of discovery could have prevented the fulfillment of the safety function of structures or systems that are needed to mitigate the consequences of an accident.

Contrary to the above, the licensee failed to notify the NRC Operations Center via the Emergency Notification System of a non-emergency event specified in Paragraph (b) within eight hours after discovery of an event on April 18, 2013. Specifically, the Unit 1 LPCS system was discovered to be inoperable, which at the time of discovery could have prevented fulfillment of the safety function of a system needed to mitigate the consequences of an accident. This Severity Level IV Violation of the NRC reporting requirements is associated with a Green SDP finding and will be treated as a non-cited violation, consistent with Section 2.3.2 of the NRC Enforcement Policy

(NCV 05000373/2013009-02, Failure to Satisfy 10 CFR 50.72 Reporting Requirements). The licensee entered this finding into its CAP as AR 01506533.

(2) Unit 1 LPCS Injection Valve Control Switch Failure

Background Information

The LPCS injection valve, 1E21-F005, opens automatically when an ESF actuation signal is present, there is no under-voltage on switchgear 141Y, and the pressure downstream of the valve in both the reactor and the injection line is less than the setpoint value. Control switch S2 is the injection valve manual opening/closing switch, which is spring-returned to the "AUTO" position. The valve can be opened by placing the control switch in the "OPEN" position (contact 1-1T of the switch closed), provided contact 5-6 of the K8 relay (pressure permissive relay) is closed. However, high resistance of control switch S2 contact 1-1T may not allow sufficient voltage across the open contact coil for 1E21-F005. This would prevent manual opening of the valve from the control room, but does not prevent the automatic opening of 1E21-F005 when the switch is in the "AUTO" position because none of the contacts of S2 are used in the auto-opening circuit of the valve.

While attempting to raise Unit 1 reactor level by using the LPCS system, control room operators held the associated control switch (S2) in the "OPEN" position but injection valve 1E21-F005 failed to open. A non-licensed operator dispatched to the 1H13-P629 panel to check the status of low pressure injection permissive relays K8 and K20 reported both relays were energized with all contact "fingers" properly aligned and making physical contact. The licensee then initiated a work order to troubleshoot the problem and found that switch S2 contact 1-1T had high resistance. The licensee changed out the control switch and performed post-maintenance testing to ensure that the contact and the LPCS valve worked as designed.

Conclusion

The inspectors determined that the licensee took immediate and appropriate corrective actions to fix the problem and restore operability to the LPCS valve. No issues of concern were identified with the control switch failure.

.6 Review the licensee's evaluation of the co-loading of the Unit 1 and Unit 2 Division 1 loads onto the swing (i.e., common unit) EDG.

a. Inspection Scope

During the licensee's initial response to the dual-unit scram and LOOP, operators questioned the appropriateness of the co-loading of the two loads onto the swing EDG. To assess this concern, the inspectors reviewed the electrical schematic diagrams of the circuit breakers that connect the swing EDG to its respective 4.16-kV safety buses and interviewed members of the licensee's staff.

b. Findings and Observations

No findings were identified. However, weaknesses in licensed operator knowledge of the expected response to a simultaneous under-voltage condition affecting both Unit 1 and Unit 2 Division 1 safety buses were apparent during the event and warrant additional attention by the licensee to improve through training.

Background Information

On April 17, at 2:59 p.m., following the dual-unit scram and LOOP, the station's five EDGs immediately started, successfully loaded onto their respective safety-related buses, and began supplying power to the buses to support operation of essential loads. The Unit 1 and Unit 2 Division 1 safety buses (141Y and 241Y, respectively) share a common unit (or "swing") EDG, which normally provides emergency power to only one unit. The Unit 1 and Unit 2 Divisions 2 and 3 safety buses are each provided with a separate EDG to provide emergency power.

During a LOOP, the 1427-AP037X1 relay would sense the under-voltage condition on the Unit 1 Division 1 safety bus 141Y and energize the 52CX1 relay for air circuit breaker (ACB) 1413. ACB 1413 is the swing EDG output breaker supplying bus 141Y. This logic string also requires that all the other ACBs that could provide power to bus 141Y are open, that ACB 2413 is not closed, and that the 86 lockout device is not picked up for ACB 1412. ACB 2413 is the swing EDG output breaker supplying bus 241Y and ACB 1412 is the normal offsite power supply breaker to bus 141Y from the station auxiliary transformer.

At the same time, the swing EDG would start due to the bus 141Y under-voltage condition via the 1427-AP037X3 relay. Once the swing EDG starts, the 1427-DG006 (59N) relay would sense the output voltage from the EDG and pick up the 59N 11-12 contact at the appropriate voltage level and this would energize the 59X relay. This satisfies a voltage permissive in the closing circuit for both ACB 1413 and ACB 2413. When the swing EDG speed reaches 870 revolutions-per-minute (approximately 8 seconds after starting), the K57 relay would energize and pick up the K57 1-2 contact. This satisfies a frequency permissive in the closing circuit for both ACB 1413 and ACB 2413. If the 86 lockout device is not picked up for the swing EDG, the ACB 1413 breaker would close to re-energize bus 141Y.

The circuit logic for Unit 2 Division 1 safety bus 241Y would operate in an identical manner as described above for Unit 1 bus 141Y. Both ACBs 1413 and 2413 use 52S/b contacts (closed when opposite breaker is open / open when opposite breaker is closed) in their breaker closing logic to prevent the other unit's breaker from being closed while one breaker is already closed. The 52S/b contact (a normally closed auxiliary contact) is supplied from the other unit's EDG bus breaker and is associated with the 52CX1 relay closing circuit.

When a loss of both buses 141Y and 241Y occurs simultaneously, which happened during the April 17th dual-unit scram and LOOP, this interlock (52S/b contacts) may not prevent both breakers from closing in at the same moment. This is because the voltage and frequency permissive signals for closing both breakers will be initiated and received at the same time. It is an unusual circumstance for simultaneous initiating signals to be sent to the EDG control logic; however, the design does not preclude this as the logic will not preferentially filter one unit's relay over the other unit's relay. A review by the inspectors of Calculation L-003364, "Auxiliary Power Analysis," Revision 1, verified that the total auto-connected loading on the swing EDG is within its continuous rating of 2600 kilo-Watts when the EDG is connected to both buses 141Y and 241Y with no LOCA.

The inspectors found no licensing commitments related to connecting the swing EDG to both buses 141Y and 241Y simultaneously. While this condition was unexpected by licensed operators during the event, it is consistent with the LaSalle swing EDG control circuit design.

Conclusion

The inspectors reviewed the electrical schematic diagrams for ACBs 1413 and 2413 and determined that the concurrent loss of voltage on buses 141Y and 241Y would not preclude simultaneous closure of both breakers onto their respective buses, in conformance with the LaSalle design. The inspectors also determined that the total loading on the swing EDG was within its continuous rating of 2600 kilo-Watts when the EDG was connected to both buses 141Y and 241Y with no LOCA.

No issues or concerns were identified with the co-loading of the Unit 1 and Unit 2 Division 1 loads onto the swing EDG during the event. AR 01504622 was written specifically to address licensed operator knowledge weaknesses regarding the expected response to a simultaneous under-voltage condition affecting both Unit 1 and Unit 2 Division 1 safety buses. In response to the inspectors' questions regarding this and other apparent licensed operator knowledge weaknesses during the event, the licensee wrote AR 01522619 and initiated a common cause evaluation to identify appropriate corrective actions, including operator training.

.7 Review the increase in and subsequent operator venting of drywell pressure during the event. Include the adequacy of any radiological monitoring of venting activities.

a. Inspection Scope

The inspectors reviewed applicable sections of the UFSAR and TSs, control room logs, effluent radiological sampling results, CAP action requests, plant process computer data and plots, plant operating procedures, and interviewed members of the licensee's staff.

b. Findings and Observations

No findings were identified.

Drywell temperature and pressure increased as expected for both units during the event as operators worked to restore non-emergency power, instrument air, and plant service water systems that were needed to support operation of drywell cooling and containment ventilation system filtering trains.

Unit 1 and 2 Background Information

As expected for a LOOP, the primary containment cooling and ventilation system was not available to remove heat from the drywells. Main steam isolation valves on both units shut due to the loss of power and; therefore, the normal decay heat removal path using the main condenser was not available. Operators used the RCIC system and safety relief valves (SRVs) for decay heat removal and reactor vessel level and pressure control. Both of these systems discharged steam into the suppression pool, which added heat to the drywells of both units, and as expected, contributed to the rise in drywell temperature and pressure.

Drywell pressure initially rose rapidly (but not excessively so) for each unit. Approximately 6 minutes into the event, Unit 2 drywell pressure reached the TS limit of 0.75 pounds-per-square-inch-gage (psig). Approximately 9 minutes into the event, Unit 1 drywell pressure reached the TS limit of 0.75 psig (the drywell design limit is about 45 psig).

Operators attempted to limit the rise in drywell pressure through controlled venting in accordance with the plant response procedure. The primary containment vent and purge (VQ) system was not available due to the LOOP. The standby gas treatment (VG) system was available and started automatically due to the primary containment isolation system initiation of Group 4 during the initial loss of power. However, due to the Group 4 primary containment isolation, VQ system valves required to be opened to establish a vent path were interlocked closed. After the emergency buses were reenergized by the EDGs, operators restarted the reactor protection system motor generator sets to restore power to the reactor protection and primary containment isolation systems. Operators then reset the Group 4 isolation, which allowed use of valves needed for drywell venting through 2-inch motor-operated valves from the drywell. This relatively small venting path was insufficient to arrest the rise in drywell pressure during the event. Larger 26-inch air-operated valves installed in parallel could not be opened to facilitate venting due to the loss of instrument air system pressure. Loss of instrument air was expected due to the unavailability of station air compressors, which are not powered by the EDGs.

Unit 2 Venting

Operators first attempted venting the Unit 2 drywell using the VG system since Unit 2 had a slightly higher drywell pressure than Unit 1. Venting was commenced on April 17 at 4:54 p.m., about 2 hours into the event. Venting was secured at 5:21 p.m. when Unit 2 drywell pressure reached the high drywell pressure primary containment isolation actuation setpoint of 1.77 psig. As stated above, venting through the 2-inch line had minimal effect on drywell pressure. Initial drywell pressure at the time venting commenced was about 1.7 psig and was reduced about 0.1 psig. Drywell pressure subsequently stabilized at about 3.0 psig before the primary containment cooling and ventilation system was restored to service at 12:55 a.m. on April 18. With the normal drywell cooling system in service, drywell pressure gradually lowered and was less than 0.60 psig at 1:49 p.m. on April 18.

Unit 1 Venting

Operators began venting the Unit 1 drywell using the VG system after the Unit 2 primary containment isolation. Venting was commenced on April 17 at 5:23 p.m., about 2 hours and 24 minutes into the event. Venting was secured at 8:04 p.m. when Unit 1 drywell pressure reached the high drywell pressure primary containment isolation actuation setpoint of 1.77 psig. As with Unit 2, venting through the 2-inch line had minimal effect on drywell pressure. Initial drywell pressure at the time venting commenced was about 1.7 psig and was reduced about 0.1 psig. Drywell pressure subsequently stabilized at about 3.0 psig before the primary containment cooling and ventilation system was restored to service at 12:22 a.m. on April 18. With the normal drywell cooling system in service, drywell pressure gradually lowered. Drywell pressure was less than 0.60 psig at 10:50 a.m. on April 18.

Radiological Monitoring of Venting Activities

Both VG trains started automatically due to the primary containment isolation system signal and operators secured the Unit 2 VG system by procedure in order to ensure proper (isokinetic) flow through the wide range gas monitor (WRGM).

Operators subsequently observed an error code on the station vent stack WRGM and declared it inoperable. Using the Offsite Dose Calculation Manual required actions of sampling every 8 hours, the licensee initiated Chemistry sampling of the VG process stream. The first sample was taken at 5:55 p.m. on April 17. Sampling continued every 4 to 6 hours with the last sample taken at 1:21 a.m. on April 19. The WRGM system was returned to service to monitor the effluent stream at 4:25 a.m. on April 19. No unexpected increase in the radiological content of the stack flow was encountered during or after the Chemistry sampling.

The licensee subsequently concluded that the WRGM data were correct and the alarm code that was present and caused operators to declare the monitor inoperable was due to the loss of power. The WRGM was found to be functioning properly, the data base was verified to be accurate, and the alarm code was cleared.

Conclusion

No issues of concern were identified with drywell pressure control and radiological monitoring of venting activities. The licensee wrote AR 01504628 to review drywell venting efforts during the event for potential procedure or design improvements.

.8 Review the post-event identification of a leak on the Unit 2 HPCS minimum flow line.

a. Inspection Scope

The inspectors reviewed applicable sections of the UFSAR and TSs, control room logs, CAP action requests, plant drawings, maintenance work orders, and interviewed members of the licensee's staff. The inspectors also reviewed details of the repair and extent of condition evaluation of other elbows and piping sections on the minimum flow lines for both units' HPCS systems.

b. Findings and Observations

No findings were identified.

On April 18, at 2:00 p.m., the licensee identified three grouped, pencil-sized, through-wall leaks on the first elbow downstream of a flow reducing orifice on the Unit 2 HPCS minimum flow line. The total leakage was estimated to be about ½ gallon-per-minute. Because of the location (i.e., just before the minimum flow line connection to the full flow test line and return to the suppression pool), the leaks were not isolable from the suppression pool and could have affected the operability of the HPCS system and primary containment. Operators declared the Unit 2 HPCS system and primary containment inoperable and implemented the applicable TS actions. The licensee made the required 8-hour notification call to the Headquarters Operations Officer (Event Notification 48943) to report the degraded condition and loss of safety function. Though declared inoperable, the Unit 2 HPCS system remained available for operation until 9:00 a.m. on April 21 when the water leg pump was secured to support repair of the elbow.

The preliminary cause of the leaks was believed to be cavitation-induced erosion of the elbow. The inspectors reviewed details of the repair and identified no issues of concern. The affected elbow was cut out and a new one welded in its place. The inspectors also reviewed the licensee's extent of condition evaluation. The evaluation included the HPCS piping downstream of the flow reducing orifice along with the three elbows on the minimum flow lines downstream of the orifice on both units' HPCS systems. The licensee noted that similar erosion was seen through ultrasonic examination on the same elbow on Unit 1; however, sufficient wall thickness still remained and no repair was performed. The inspectors reviewed the licensee's evaluation (vendor analysis) that accepted the condition as is. At the conclusion of this inspection, the licensee had not yet completed a causal analysis for the leaks. The resident inspectors will review the analysis when it is completed, as part of baseline inspection activities.

.9 Review suppression pool level for both units during the event.

a. Inspection Scope

The inspectors reviewed applicable sections of the UFSAR and TSs, control room logs, CAP action requests, plant process computer data and plots, plant operating procedures, and interviewed members of the licensee's staff.

b. Findings and Observations

No findings were identified.

Suppression pool levels for both units rose as expected during the event. Operators used the RCIC system and SRVs for decay heat removal and for reactor vessel level and pressure control. Both of these systems discharged steam to the suppression pool, which added inventory. Unit 1 suppression pool level reached 4.8 feet and Unit 2 suppression pool level reached 3.4 feet during the event. The TS limit for suppression pool level with the units in Modes 1, 2, and 3 is 3 inches and the required action for level over 3 inches is to enter Mode 4 within 36 hours. Unit 1 entered Mode 4 on April 18 at 5:58 p.m. and Unit 2 entered Mode 4 on April 19 at 2:50 a.m., both within the 36-hour TS limit. Suppression pool levels peaked when operators swapped RCIC pump suction from the condensate storage tank to the suppression pool and then lowered as operators began de-inerting the drywells and initiated suppression pool cooling with the RHR system. This occurred on April 18 at about 9:30 a.m. for Unit 1 and 12:30 p.m. for Unit 2. No issues of concern were identified with the licensee's control of suppression pool level during the event.

.10 Review the performance of the SRVs used to control reactor pressure during the event.

a. Inspection Scope

The inspectors reviewed applicable sections of the UFSAR and TSs, control room logs; corrective action program action requests, plant process computer data and plots, plant operating procedures, and plant drawings associated with operation of the SRVs, and interviewed members of the licensee's staff.

b. Findings and Observations

No findings were identified.

The SRVs performed as designed during the event; however, weaknesses in licensed operator knowledge of the expected SRV responses were apparent during the event and warrant additional attention by the licensee to improve through training.

Unit 1 Background Information

During the scram, the 4 Unit 1 SRVs (1U, 1C, 1S, and 1E) within the lowest pressure setpoint band lifted as expected. Initially following the scram, peak reactor pressure information was not available to determine the exact lift pressure for each SRV. After the first 2 SRVs lifted (1U and 1C), the low-low set (LLS) function was initiated and changed the set pressures for both lift and blowdown of the LLS SRVs with the 1S and 1U SRVs having the lowest reset values. The 1C and 1E SRVs closed first as expected, which was followed by the 1S SRV, and then the 1U SRV. With the LLS function initiated, this was the expected sequencing of the SRVs. The 1U SRV closed at 3:01:11 p.m. on April 17 and, per the control room logs, Unit 1 established reactor pressure control at 450-650 psig using SRVs. This is below the pressure setpoints of the LLS pressure switches, so from this point on, SRV operation was manual.

Unit 2 Background Information

During the scram, the 3 SRVs (2U, 2C, and 2S) within the lowest pressure setpoint band lifted as expected. Initially following the scram, peak reactor pressure information was not available to determine the exact lift pressure for each SRV. After the first 2 SRVs lifted (2U and 2C), the LLS function was initiated and changed the set pressures for both lift and blowdown of the LLS SRVs with 2S and 2U SRVs having the lowest reset values. The SRVs sequenced closed as expected, which was the 2C SRV, then the 2S SRV, followed by the 2U SRV. The 2U SRV closed at 3:01:29 p.m. on April 17 and, per the control room logs, Unit 2 established reactor pressure control at 450-650 psig using SRVs. This is below the pressure setpoints of the LLS pressure switches, so from this point on, SRV operation was manual.

Reports of Non-Functioning SRVs During the Event

Three Unit 1 SRVs (1U, 1C, and 1S) and 1 Unit 2 SRV (2C) were reported to no longer function on their non-automatic depressurization system (ADS) accumulators. The 10-gallon accumulators ran out of air capacity after 3 hours. The SRVs were re-aligned to the ADS accumulators, which are 40-gallons with bottle bank backup. This complies with the design expectations. The 10-gallon accumulators are sized for one lift at full RCS pressure and maximum drywell pressure of 45 psig. Each of the above 4 SRVs cycled 3 times during the event on the non-ADS accumulators. No issues of concern were identified with SRV operations; however, it was apparent that licensed operators did not clearly understand the observed SRV performance during the event as the 10-gallon accumulators ran out of air.

The above SRVs experienced position indication issues from dual to no indication. The position indication issues occurred at about the same time as the non-ADS accumulators were running low on air pressure. Declining air pressure available to the SRVs decreased the ability to fully lift the valves against spring pressure and caused the position indication issues experienced during the event. When the SRV is electrically opened it will only open as far as the actuator will drive it as long as the valve is below the reseat value (approximately 90 psig from spring set pressure) or the valve will fully open; however, at the time this was encountered, reactor pressure was being controlled well below the valve reseat value. Therefore, with low air pressure, it is possible to have a partial lift of the valve allowing pressure to be relieved without proper valve indication. After instrument air was restored to the containments at 11:17 p.m. on April 17, no additional position indication issues were noted and the SRVs operated normally to the full open position.

Conclusion

The SRVs and SRV position indication functioned as expected during the event. ARs 01503454, 01503463, 01503464, and 01503626 were written to document the problems reported with the 4 SRVs. The inspectors noted that all 4 of the action requests were closed with no corrective actions assigned to address the licensed operator knowledge weaknesses. However, in response to the inspectors' questions regarding this and other apparent licensed operator knowledge weaknesses during the event, the licensee wrote AR 01522619 and initiated a common cause evaluation to evaluate operator knowledge weaknesses from the event.

.11 Review the circumstances of the post-event need to replace seals of the Unit 2 reactor recirculation pumps.

a. Inspection Scope

The inspectors reviewed control room logs, CAP action requests, plant process computer data and plots, plant operating procedures, and interviewed members of the licensee's staff.

b. Findings and Observations

No findings were identified.

The licensee replaced the Unit 2 reactor recirculation pump seals based on exceeding temperature limits established by the licensee after a review of the pump seal vendor's technical manual and after consultation with the vendor. No seal failure occurred during the event; however, seal replacement was deemed by the licensee to be prudent prior to unit restart and operation for the remainder of the fuel cycle. Replacement of pump seals was not considered necessary by the licensee for the Unit 1 reactor recirculation pumps because temperature limits were not exceeded. Beginning with the LOOP on April 17, Unit 2 was without control rod drive (CRD) system flow, which provides cooling to pump seals, for about 3½ days, while Unit 1 lost CRD flow for only about ½ hour. The Unit 2 reactor recirculation pump seal temperatures were off-scale high (greater than 300 degrees Fahrenheit) for about 14 hours during the 3½-day period.

Maintaining CRD flow versus not maintaining CRD flow was driven by operating procedure based upon the reactor vessel level control band. Although restoration of CRD flow to the pump seals following a LOOP where component cooling water flow to the seals is lost would help to maintain seal temperature low and avoid seal damage, there is also a concern that restoring CRD flow would inject cold water into the reactor pressure vessel bottom head area with no forced circulation flow. The licensee wrote AR 01505675 to develop an appropriate CRD system restart strategy (i.e., implementing appropriate operating procedure revisions) with consideration for the impact on the reactor recirculation pump seals and reactor pressure vessel temperature stratification. No issues of concern were identified.

.12 Review the adequacy of the restoration of nonsafety-related service water to the drywell coolers.

a. Inspection Scope

In discussions with the NRC during the initial hours after the April 17 dual-unit scram and LOOP, the licensee indicated that restoration of the nonsafety-related service water system might require extensive effort. To review this issue, the inspectors reviewed control room logs, CAP action requests, plant process computer data and plots, plant operating procedures, and interviewed members of the licensee's staff.

b. Findings and Observations

No findings were identified.

Based on the information reviewed by the inspectors, no issues of concern were identified with the restoration of the plant service water system and the primary containment cooling and ventilation system for Units 1 and 2.

The licensee's own review of the issue noted that its procedure for service water system startup (LOP-WS-01) lacked sufficient guidance to allow operators to quickly restore the system from a loss of all service water that required refilling and venting of the system. The licensee wrote AR 01504600 to improve the procedural guidance. Notwithstanding the procedure, operators were able to restore the system to service early in the morning of April 18.

4OA6 Meetings, Including Exit

On April 26, 2013, the inspectors presented the preliminary inspection results to Mr. H. Vinyard and other members of the licensee's staff during a pre-exit debrief upon completion of the onsite inspection activities.

On May 21, 2013, several of the inspectors met with the licensee at its Warrenville, Illinois, corporate headquarters to discuss the status of the root cause evaluation.

On June 3, 2013, the inspectors presented the inspection results to Mr. H. Vinyard and other members of the licensee's staff at the conclusion of the inspection. The licensee acknowledged the findings presented. No proprietary information is included in this inspection report.

Attachments:
1. Supplemental Information
2. Memo to Kemker
3. LaSalle Timeline

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

L. Blunk, Regulatory Assurance
B. Cockrel, Engineering
G. Ford, Regulatory Assurance Manager
J. Greenblott, Engineering
J. Keenan, Shift Operations Superintendent
J. Kowalski, Engineering Development Manager
G. Lechtenberg, Training
B. Lind, Training
M. Martin, Chemistry
K. Rusley, Emergency Preparedness Manager
D. Schmit, Engineering
E. Seckinger, Engineering
P. Simpson, Licensing Manager
S. Smalley, Engineering
H. Vinyard, Plant Manager

NRC Personnel

R. Ruiz, Senior Resident Inspector, LaSalle County Station
F. Ramírez, Resident Inspector, LaSalle County Station
C. Pederson, Deputy Regional Administrator
K. O'Brien, Deputy Director, Division of Reactor Projects
M. Kunowski, Chief, Reactor Projects, Branch 5
R. Daley, Chief, Engineering Branch 3

LIST OF ITEMS OPENED, CLOSED, DISCUSSED

Opened

05000373/2013009-01 05000374/2013009-01	URI	Review of the Loss of Offsite Power Event Root Cause Evaluation and Switchyard Design Basis (Section 4OA5.3)
05000373/2013009-02	NCV	Failure to Satisfy 10 CFR 50.72 Reporting Requirements (Section 4OA5.5)

Closed

05000373/2013009-02	NCV	Failure to Satisfy 10 CFR 50.72 Reporting Requirements (Section 4OA5.5)

LIST OF DOCUMENTS REVIEWED

The following is a list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspectors reviewed the documents in their entirety, but rather, that selected sections of portions of the documents were evaluated as part of the overall inspection effort. Inclusion of a document on this list does not imply NRC acceptance of the document or any part of it, unless this is stated in the body of the inspection report.

Drawings	Title	Revision
ISI-HP-1006	LaSalle County Station Unit 1 Inservice Inspection Isometric – High Pressure Core Spray System	A
ISI-HP-2006	LaSalle County Station Unit 2 Inservice Inspection Isometric – High Pressure Core Spray System	A
M-95	P&ID High Pressure Core Spray (HPCS)	AP
M-141	P&ID High Pressure Core Spray (HPCS)	AS
1E-0-4412AA	Schematic Diagram 4160V Switchgear 141Y Diesel Generator “O” Feed ACB 1413 System “DG”	AD
1E-0-4412AB	Schematic Diagram 4160V Switchgear 241Y (2AP04E) Diesel Generator “O” Feed ACB 2413 System “DG”	AB
1E-0-4412AF	Schematic Diagram Diesel Generator “O” Generator/Engine Control System “DG”	V
1E-0-4412AH	Schematic Diagram Diesel Generator “O” Generator/Engine Control System “DG”	R
1E-2-4220AD	Schematic Diagram Residual Heat Removal Pump 2C System RH	U
1E-2-4220AH	Schematic Diagram Residual Heat Removal Pump 2C System RH	W
1E-2-4220AK	Schematic Diagram Residual Heat Removal Pump 2C System RH	S
1E-2-4220AL	Schematic Diagram Residual Heat Removal Pump 2C System RH	W
1E-1-4221AB	Schematic Diagram Low Pressure Core Spray System “LP”	T
1E-1-4221AD	Schematic Diagram Low Pressure Core Spray System “LP”	Y
1E-0-1020	Plan of Grounding 345-kV Switchyard – North Half	C
1E-0-1021	Plan of Grounding 345-kV Switchyard – South Half	C
1E-0-1020A	Plan of Grounding 138-kV Switchyard	H
1E-0-4022	One Line Diagram 345-kV Auxiliary Power System	F
1E-0-4024	Wiring Diagram of 125 VDC Power for 345-kV Switchyard	Q
1E-0-4002F	Schematic Diagram System 2 Protective Relaying DC Circuits & Transfer Trip Communications 345-kV L0101	C
1E-0-4016B	Schematic Diagram Control Circuits for 345-kV BT 1-9 CB	N
1E-0-4026B	Schematic Diagram of Tripping Connection TR. 81	H
1E-0-4064E	Schematic Diagram of Control Circuits for 138-kV CB Line 0112	F

Action Requests	Title
AR 01503454	2C SRV Did Not Open When MCR [Main Control Room] Control Switch Placed in Open
AR 01503463	1S SRV Did Not Open When MCR Control Switch Placed in Open
AR 01503464	1C SRV Did Not Open When MCR Control Switch Placed in Open
AR 01503626	No Open Indication When 1U SRV Taken Open
AR 01503825	Through Pipe Leak at 90 Degree Elbow in 673’ Raceway
AR 01503846	U1 HPCS Extent of Condition
AR 01504337	Unit 1 HPCS Minimum Flow Piping NDE Preliminary Results
AR 01503438	SBGT [Standby Gas Treatment] WRGM Displayed Data Base Fault Following Loss of Power
AR 01503616	SVS [Station Ventilation Stack] WRGM Channel Activity Recorder Requires Replacement
AR 01504591	Review of VG and SVS WRGM Performance Post-Scram
AR 01504600	Service Water Start Procedure Improvement
AR 01505765	ODCM [Off-Site Dose Calculation Manual] Effluent Monitoring Instrumentation – Dual-unit LOOP
AR 01505772	Drywell Atmosphere Samples Delayed Due to PCIS [Primary Containment Isolation System] and No Power
AR 01504628	Containment Vent Strategies
AR 01506533	NRC Identified U1 LPCS Inoperable Reportability
AR 01503723	Unit 1 LPCS Injection Valve 1E21-F005 Will Not Open
AR 01503446	Common DG Started And Repowered Both Bus 141Y and 241Y
AR 01503444	Delay in Closing ACB 2412 to Restore SAT to Bus 241Y
AR 01503431	0 DG Tied to Both Units During Transient
AR 01503428	138-kV Line 0112 Damaged by Lightning Strike
AR 01503410	Unit 2 Scram Caused by Loss of Offsite Power
AR 01503409	Unit 1 Scram Caused by Loss of Offsite Power
AR 01503396	1C VC [Control Room Ventilation] Radiation Monitor 1D18-K751C Failed
AR 01503394	2B VC Radiation Monitor 2D18-K751B Failed
AR 01503380	2C RHR Pump Failed to Start
AR 01504857	Review of Operations Logs for 4/17/13 Transient
AR 01504820	UFSAR Inconsistency Identified During Engineering Review
AR 01504622	Operations CRC Review for Training Issue
AR 01504868	LGA-VQ-01 Procedure Revision Recommendation
AR 01504866	Update to ENS Notification Performed
AR 01505772	Drywell Atmosphere Samples Delayed Due to PCIS and No Power
AR 01518242	Operations Crew 6 4/1/13 LOOP Lessons Learned
AR 01503967	Replace 2A and 2B Reactor Recirculation Pump Seals During L2F42
AR 01505675	Control Rod Drive Restart Strategy for Reactor Recirculation Seals or Stratification
AR 01522619	Perform Common Cause Analysis on Operations Knowledge Gaps from LOOP
AR 01504675	2C RHR Pump Trip During LOOP Troubleshooting Findings

Documents	Title	Date/Revision
	LaSalle County Station Unit 1 and 2 Updated Final Safety Analysis Report	
	LaSalle County Station Unit 1 and 2 Technical Specifications	
	LaSalle County Station Unit 1 and 2 Technical Requirements Manual	
	Unit 1 Post-Transient Trip Review	April 17, 2013
	Unit 2 Post-Transient Trip Review	April 17, 2013
	Unit 1 Control Room Operator Logs	April 16-22, 2013
	Unit 2 Control Room Operator Logs	April 16-22, 2013
	Hathaway Printer Log, LaSalle Nuclear Station, Unit 1 Annunciator Alarm Summary	April 17, 2013
	Hathaway Printer Log, LaSalle Nuclear Station, Unit 2 Annunciator Alarm Summary	April 17, 2013
EN 48939	Notification of Unusual Event Declared Due to Loss of Offsite Power from a Lightning Strike	April 17, 2013
EC 393403	Evaluation of Readiness of Unit 1 Start-up from L1F41	Revision 0
Module/LP ID: 062	Operations Training Program – Initial and Continuing Training: Automatic Depressurization System	Revision 6 March 9, 2012
Module/LP ID: 070	System Description: Main Steam System	Revision 8 March 9, 2012
LGA-001	RPV [Reactor Pressure Vessel] Control	Revision 13
LGA-003	Primary Containment Control	Revision 13
LOA-RR-101	Unit 1 Reactor Recirculation System Abnormal	Revision 32
LOA-RR-102	Unit 2 Reactor Recirculation System Abnormal	Revision 32
LGA-VQ-04	Startup, Shutdown, and Operations of the Primary Containment Vent and Purge System	Revision 34
LOP-WS-01	Service Water System Startup	Revision 12
E13-309	VT-2 Visual Examination NDE Report (WO 1635334) of 2HP09A-6”	April 23, 2013
13-047	Magnetic Particle Examination Report (WO 1635334-04) of 2HP09A-6”	April 22, 2013
13-048	Radiographic Examination and Interpretation Report (WO 1635334-04) of Weld 1 on 2HP09A-6”	April 23, 2013
13-049	Radiographic Examination and Interpretation Report (WO 1635334-04) of Weld 2 on 2HP09A-6”	April 23, 2013
EC 393401	Minimum Wall Evaluation for HPCS Minimum Flow Lines 1/2HP09A-6”	Revision 2
1300581.401.R0	Letter from Structural Integrity Associates, Inc., Subject: LaSalle High Pressure Core Spray Piping Elbow Wall Thinning Evaluation	April 20, 2013
WO 01635336	Unit 1 HPCS Extent of Condition	

Documents	Title	Date/Revision
WO 01635134-01	Unit 1 LPCS Injection Valve 1E21-F005 Will Not Open	
WO 01635134-02	PMT [Post Maintenance Test] Unit 1 LPCS Injection Valve 1E21-F005 Will Not Open	
Module/LP ID 095	Operations Training Program – Initial and Continuing Training: Standby Gas Treatment System (VG)	Revision 9 December 4, 2011
Module/LP ID 093	Operations Training Program – Initial and Continuing Training: Containment Vent and Purge	Revision 5 June 18, 2008
Module/LP ID 052	Operations Training Program – Initial and Continuing Training: Process Radiation Monitoring	Revision 8 September 12, 2012
Module/LP ID 112	Operations Training Program – Initial and Continuing Training: Service Water (WS)	Revision 11 June 14, 2012

LIST OF ACRONYMS USED

ACB	Air Circuit Breaker
ADAMS	Agencywide Document Access Management System
ADS	Automatic Depressurization System
AR	Action Request
CAP	Corrective Action Program
CFR	Code of Federal Regulations
CRD	Control Rod Drive
DC	Direct Current
ºF	Degrees Fahrenheit
EC	Engineering Change
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
ESF	Engineered Safety Features
HPCS	High Pressure Core Spray
IMC	Inspection Manual Chapter
kV	Kilovolt
LLC	Limited Liability Corporation
LLS	Low-Low Set
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
LPCI	Low Pressure Coolant Injection
LPCS	Low Pressure Core Spray
MCR	Main Control Room
NCV	Non-Cited Violation
NOUE	Notification of Unusual Event
NRC	U.S. Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
NSIR	Nuclear Security and Incident Response
ODCM	Off-Site Dose Calculation Manual
PARS	Publicly Available Records System
PCIS	Primary Containment Isolation System
PMT	Post-Maintenance Test
psig	pounds-per-square-inch-gage
RCIC	Reactor Core Isolation Cooling
RHR	Residual Heat Removal
RPV	Reactor Pressure Vessel
SBGT	Standby Gas Treatment
SDP	Significance Determination Process
SIT	Special Inspection Team
SRV	Safety Relief Valve
STA	Station
SVS	Station Ventilation Stack
TS	Technical Specification
TSS	Transmission Sub-Station
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
VC	Control Room Ventilation
VDC	Volts Direct Current
VG	Standby Gas Treatment
VQ	Primary Containment Vent and Purge
WO	Work Order

WRGM	Wide Range Gas Monitor

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
2443 WARRENVILLE ROAD, SUITE 210
LISLE, IL 60532-4352

April 26, 2013

MEMORANDUM TO: Brian Kemker, Senior Resident Inspector
Clinton Power Station

FROM: Steven Reynolds, Director ***/RA/***
Division of Reactor Projects

SUBJECT: SPECIAL INSPECTION CHARTER FOR DUAL-UNIT LOSS-OF-OFFSITE POWER AND REACTOR SCRAM AT LASALLE COUNTY STATION, UNITS 1 AND 2, APRIL 17, 2013

On April 17, 2013, at 2:59 p.m. (CDT), LaSalle Units 1 and 2 automatically scrammed from 100% power, in conjunction with a loss of offsite power. The loss of offsite power appears to have been caused by a lightning strike in the main 345-kiloVolt (kV)/138-kV switchyard during a thunderstorm. The licensee declared a Notification of Unusual Event (NOUE) at 3:11 p.m. because of the loss of offsite power. The licensee was able to restore offsite power and exited the NOUE at 8:14 a.m. the following day, April 18.

Following the scrams of both reactors, most of the plant safety-related equipment responded as expected. Exceptions were the failure of the Unit 2 C residual heat removal (RHR) pump to start and the failure to open of the Unit 1 1E21-F005 Low Pressure Core Spray (LPCS) injection valve. Both failures apparently had no significant effect on the ability of operators to respond to the event. In addition, during the NRC's monitoring of the licensee's response to the event and subsequently, questions arose from the NRC staff about the performance of certain nonsafety-related equipment.

Based on the deterministic criteria provided in Management Directive (MD) 8.3, NRC Incident Investigation Program, the incident met MD 8.3 criterion f, in that it apparently involved significant unexpected system interactions. Specifically, a lightning strike to a component of the 138-kV electrical system in the switchyard resulted in the opening of all breakers in the 345-kV electrical system ring bus and the loss of offsite power to both LaSalle units. Section 8.2.3.2, Adequacy of Offsite Power, and section 8.1.2.5, Unit Non-Class 1E D-C [direct current] of the LaSalle Updated Final Safety Analysis Report indicate that this type of loss of offsite power should not have occurred. Region III Senior Reactor Analysts completed a SPAR model event assessment modeled as a dual-unit loss of offsite power event with a failure to run of the 2C RHR pump and a failure of the Unit 1 LPCS injection valve to open. The assessment resulted in an estimated Conditional Core Damage Probability (CCDP) value of approximately 5.8E-5 for Unit 1 and 1.0E-4 for Unit 2.

CONTACT: Mike Kunowski, DRP
630-829-9618

Attachment 2

Accordingly, based on the deterministic and risk criteria in MD 8.3, and after consultation with NRR and NSIR, a Special Inspection Team (SIT) will commence an inspection, effective on April 22, 2013. The SIT will be led by you and will include Mohammad Munir, Electrical Engineer Reactor Inspector, Region III, and Kenya Carrington, the acting Resident Inspector at LaSalle. In addition, Rob Ruiz, the LaSalle Senior Resident Inspector, and Robert Jickling, Senior Emergency Preparedness Specialist, Region III, will be available to assist.

The SIT will determine the sequence of events, and will evaluate the facts, circumstances, and the licensee's actions surrounding the April 17, 2013, event. The specific charter for the Team is enclosed.

Docket Nos. 50-373 and 50-374

Enclosure:
As stated

cc w/encl: Charles Casto
Cynthia Pederson
Harral Logaras
Steven Reynolds
Kenneth O'Brien
Gary Shear
Patrick Louden
Darrell Roberts
James Clifford
Chris Miller
Peter Wilson
Rick Croteau
William Jones
Terrence Reis
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Robert Jickling
Robert Ruiz
NRR_Reactive_Inspection Resource@nrc.gov
RidsNrrPMLaSalle Resource

LASALLE SPECIAL INSPECTION CHARTER

This Special Inspection Team is chartered to assess the circumstances surrounding the dual-unit reactor scram and loss of offsite power following a lightning strike in the 138-kV/345-kV switchyard on April 17, 2013. The Special Inspection will be conducted in accordance with Inspection Procedure 93812, "Special Inspection," and will include, but not be limited to, the items listed below.

1. Identify a time-line for the event. Include relevant and major plant conditions, system line-ups, and operator actions.

2. Review plant data and records to confirm the adequacy of the licensee's assessment of the cause of the scram of the reactors.

3. Review the circumstances of the dual-unit loss of offsite power following the lightning strike in the plant switchyard. Include a review of relevant portions of the Updated Final Safety Analysis Report that discuss the switchyard.

4. Review the licensee's evaluation of the failure of the Unit 2 C RHR pump to start.

5. Review the licensee's evaluation of the failure of the Unit 1 1E21-F005 LPCS injection valve to open.

6 Review the licensee's evaluation of the co-loading of the Unit 1 and Unit 2 division 1 loads to the swing emergency diesel generator.

7. Review the increase in, and subsequent operator venting of, drywell pressure during the event. Include the adequacy of any radiological monitoring of venting activities.

8. Review the post-event identification of a leak on the Unit 2 high pressure core spray min-flow line.

9. Review suppression pool level for both Units during the event. Following the reactor scram, the Unit 2 suppression pool rose to a level that, as required by Technical Specifications, the licensee took the Unit to Mode 4.

10. Review the performance of the safety relief valves used to control reactor pressure during the event.

11. Review the circumstances of the post-event need to replace seals of the Unit 2 reactor recirculation pumps.

12. Review the adequacy of the restoration of nonsafety-related service water to the drywell coolers.

Charter Approval

/RA/ Mike Kunowski, Chief, Branch 5, DRP

/RA/ Steve Reynolds, Director, Division of Reactor Projects

<u>LaSalle Station Dual-Unit SCRAM and LOOP</u>

Note: All times below are in Central Standard Time. Times were derived from control room operator log entries and plant process computer data. Some of the times are approximate.

<u>April 17, 2013</u>

14:57	The TSS 105 Kickapoo 138-kV Line 0112 breaker opens due to ‘C’ phase-to-ground fault caused by a lightning strike. LaSalle 138-kV L0112 circuit breaker does not reclose as a result of the ‘C’ phase coupling capacitor having incurred damage.
14:57	345-kV Circuit Breaker 9-10 trips open.
14:59	The TSS 105 Kickapoo 138-kV Line 0112 circuit breaker recloses dead.
14:59	Multiple alarms are received in the Control Room for both units: • 345-kV circuit breakers trip open; • All offsite power is lost; • Both units scram due to turbine control valve fast closure, all control rods insert; • Division 1, 2, and 3 EDGs start and load onto respective buses; and • Primary containment isolations occur (Groups 1-7, 10), main steam isolation valves close, standby gas treatment VG system actuates.
15:00	The Unit 1 and 2 Control Room supervisors direct the reactor operators to use the RCIC system and ECCS for reactor level control, and SRVs for pressure control.
15:01	Unit 1 operators manually initiate the RCIC system for reactor level control.
15:01	Unit 2 RCIC and HPCS systems actuate on a Level 2 (reactor vessel water level at -50 inches) ESF actuation signal. Level 2 isolations and actuations initiated.
15:01	The Unit 1 1U SRV closed. Unit 1 operators established reactor pressure control manually at 450-650 psig using SRVs.
15:01	The Unit 2 2U SRV closed. Unit 2 operators established reactor pressure control manually at 450-650 psig using SRVs.
15:01	Unit 1 HPCS pump actuates on a Level 2 ESF actuation signal. Level 2 isolations and actuations initiated.
15:05	Unit 2 drywell pressure rises above 0.75 psig.
15:06	Unit 1 operators start the 1A and 1B RHR pumps and establish suppression pool cooling mode.
15:08	Unit 1 drywell pressure rises above 0.75 psig.
15:08	Unit 2 HPCS and RCIC injection terminates with reactor vessel water level at Level 8.
15:10	Unit 2 operators establish reactor vessel level band of -30” to +50” using RCIC and ECCS.
15:11	The licensee declares an NOUE due to loss of offsite power.
15:13	Unit 2 VG train is placed in pull-to-lock.
15:16	The station vent stack WRGM is declared inoperable.
15:56	Unit 1 suppression pool level rises above 3 inches.
15:57	Unit 2 drywell pressure is at 1.4 psig and rising slowly. Operators begin preparations for automatic load shedding of vital buses.
15:58	Unit 1 operators secure RHR suppression pool cooling.
15:58	Unit 2 suppression pool temperature rises above 110 ºF (degrees Fahrenheit).

April 17, 2013

15:59	The licensee notifies the NRC of the NOUE.
16:00	The licensee’s Technical Support Center establishes command and control.
16:14	Unit 1 operators are no longer able to vent the Unit 1 drywell due to primary containment isolation system (PCIS) signal, Group 4 isolations.
16:20	Unit 1 operators secure the1A RHR train from suppression pool cooling mode in anticipation of losing Division 1 power due to Unit 2 primary containment pressure approaching its ESF actuation setpoint to cause the common unit EDG to transfer to Unit 2.
16:26	Unit 1 operators place the 1A RHR and LPCS pumps in pull-to-lock to secure pumps in anticipation of Division 1 AC power being de-energized.
16:28	Unit 2 receives a high drywell pressure ESF actuation signal coincident with under-voltage. Unit 1 loses Division 1 power and the common unit EDG transfers to Unit 2.
16:30	Unit 2 suppression pool level rises above 3 inches.
16:32	Unit 2 operators are not able to start the 2C RHR pump after power is restored following the Division 1 load shed.
16:32	Unit 1 operators manually open the 1C SRV to control reactor pressure but have no indication that the valve is open. Pressure response, however, appears to be normal. Operators declared the valve position indication inoperable.
16:40	Unit 2 operators establish suppression pool cooling using the 2A and 2B RHR pumps.
16:54	Unit 2 operators commence venting the Unit 2 drywell.
16:54	Unit 1 suppression pool temperature rises above 110 ºF.
17:05	Unit 1 operators restart the 1A RHR pump in suppression pool cooling mode and secure the 1B RHR pump in preparation for a Division 2 ECCS initiation signal, which will cause a Division 2 load shed.
17:20	Unit 1 operators restart the 1B RHR pump in suppression pool cooling mode.
17:21	Unit 2 receives a PCIS signal for high drywell pressure of 1.77 psig. Drywell venting terminates due to PCIS isolations.
17:23	Unit 1 operators commence venting the Unit 1 drywell.
17:45	Unit 1 operators manually open the 1U SRV but have no indication that the valve is open; however, pressure response appears to be normal. Operators declared the valve position indication inoperable.
17:55	Chemistry initiates 8-hour sampling of the VG process stream due to an inoperable station vent stack WRGM.
18:21	The Unit 1 1S SRV failed to cycle open from the control room hand switch. Operators declared the 1S SRV inoperable.
19:24	The Unit 2 station auxiliary transformer, TR-242, is reenergized. Operators begin unloading EDGs and transferring loads back onto the station auxiliary transformer.
20:04	Unit 1 receives a PCIS signal for high drywell pressure of 1.77 psig. Drywell venting terminates due to PCIS isolations.
20:20	The 0B (common unit) service water jockey pump is started for operators to begin plant service water system restoration (fill and vent of the system).
20:26	The Unit 1 station auxiliary transformer, TR-142, is reenergized. Operators begin unloading EDGs and transferring loads back onto the station auxiliary transformer.
23:10	Unit 2 operators start the Unit 2 station air compressor.

April 18, 2013

00:22 Unit 1 operators start the 1A primary containment ventilation chilled water loop, restoring Unit 1 drywell cooling and ventilation equipment.
00:40 Instrument air system low pressure alarms clear.
00:55 Unit 2 operators start the 2A primary containment ventilation chilled water loop, restoring Unit 2 drywell cooling and ventilation equipment.
01:00 Operators start the common unit station air compressor, beginning restoration of station air to Division 1 equipment on both units including ADS valves 1C and 1S.
01:17 Unit 1 operators start the 1B fuel pool cooling pump and Unit 2 operators start the 2A fuel pool cooling pump. Cooling is restored to the Unit 1 and Unit 2 spent fuel pools.
01:49 Service water pressure is restored to greater than 0.80 psig.
01:49 The Unit 2 drywell pressure is less than 0.60 psig.
04:00 The 1C SRV position indication is declared operable.
05:00 The Unit 2 drywell temperature is less than 135 ºF.
05:10 345-kV breakers 1-2 and 1-9 are closed per switching orders; Lines 0101, 0102, 0103 are now operable offsite power sources.
07:16 The licensee commences venting of the Unit 2 drywell.
07:30 The Unit 2 suppression pool temperature is less than 110 ºF.
08:14 The licensee terminates the NOUE.
08:27 Operators secured the Unit 2 HPCS pump.
09:24 Operators secured venting the Unit 2 drywell to begin de-inerting the Unit 1 drywell.
09:35 Commenced de-inerting the Unit 1 suppression chamber.
10:18 Electrical maintenance begins troubleshooting the 2C RHR pump failure to start.
10:50 The Unit 1 drywell pressure is less than 0.60 psig.
10:52 Completed de-inerting the Unit 1 suppression chamber and commenced de-inerting the Unit 1 drywell.
12:10 Unit 1 drywell is de-inerted.
12:30 Commenced de-inerting the Unit 2 suppression chamber.
13:25 Unit 1 LPCS injection valve, 1E21-005, fails to open when operators attempt to raise reactor level using the LPCS system.
13:48 Unit 2 drywell pressure is less than 0.75 psig.
13:53 Completed de-inerting the Unit 2 suppression chamber and commenced de-inerting the Unit 2 drywell.
14:00 The licensee discovers a 0.5 gallon-per-minute leak on the Unit 2 HPCS system minimum flow line.
16:40 Operators establish shutdown cooling on Unit 1.
17:58 Unit 1 enters Mode 4 (Cold Shutdown) with reactor coolant system temperature less than 200 ºF.
19:00 Unit 2 drywell is de-inerted.
20:32 ENS Notification 48943 made for an inoperable Unit 2 HPCS system.
23:30 Operators establish shutdown cooling on Unit 2.

April 19, 2013

02:50 Unit 2 enters Mode 4.
04:25 The station vent stack WRGM is operable and Chemistry sampling of the VG process stream is discontinued. The last sample was taken on April 19 at 01:21.

If you contest this Non-Cited Violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial to the Nuclear Regulatory Commission, ATTN.: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, Region III; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at LaSalle County Station.

If you disagree with the cross-cutting aspect assignment in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region III, and the NRC Resident Inspector at LaSalle County Station.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room and from the Publicly Available Records System (PARS) component of NRC's document system, Agencywide Documents Access and Management System (ADAMS). ADAMS is accessible from the NRC Website at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Steven Reynolds, Director
Division of Reactor Projects

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

Enclosure: Inspection Report 05000373/2013009; 05000374/2013009;
w/Attachments: 1. Supplemental Information
2. Memo to Kemker
3. LaSalle Timeline

cc w/encl: Distribution via ListServ™

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DATE	07/18/13		07/18/13		07/18/13			

OFFICIAL RECORD COPY

Letter to M. Pacilio from S. Reynolds dated July 18, 2013

SUBJECT: LASALLE COUNTY STATION, UNITS 1 AND 2 - NRC SPECIAL INSPECTION TEAM (SIT) INSPECTION REPORT 05000373/2013009; 05000374/2013009

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