UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
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April 28, 2017

Mr. Bryan C. Hanson
Senior VP, Exelon Generation Company, LLC
President and CNO, Exelon Nuclear
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: LASALLE COUNTY STATION, UNITS 1 AND 2—NRC INTEGRATED INSPECTION REPORT 05000373/2017001 and 05000374/2017001

Dear Mr. Hanson:

On March 31, 2017, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your LaSalle County Station, Units 1 and 2. On April 5, 2017, the NRC inspectors discussed the results of this inspection with Mr. H. Vinyard and other members of your staff. The results of this inspection are documented in the enclosed report.

Based on the results of this inspection, the NRC has identified two issues that were evaluated under the risk significance determination process as having very low safety significance (Green). The NRC has also determined that two violations are associated with these issues. Because the licensee initiated condition reports to address these issues, these violations are being treated as Non-Cited Violations (NCVs), consistent with Section 2.3.2 of the Enforcement Policy. These NCVs are described in the subject inspection report. Further, the inspectors documented a licensee-identified violation which was determined to be of very low safety significance (Green) in this report. The NRC is treating this violation as a NCV, consistent with Section 2.3.2.a of the Enforcement Policy.

If you contest the violations or significance of these NCVs, 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, Region III; the Director, Office of Enforcement, and the NRC Resident Inspector at the LaSalle County Station.

If you disagree with the cross-cutting aspect assignment or a finding not associated with a regulatory requirement 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 U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555–0001; with copies to the Regional Administrator, Region III; and the NRC Resident Inspector at the LaSalle County Station.

This letter, its enclosure, and your response (if any) will be made available for public inspection and copying at http://www.nrc.gov/reading-rm/adams.html and at the NRC Public Document Room in accordance with 10 CFR 2.390, "Public Inspections, Exemptions, Requests for Withholding."

Sincerely,

/RA/

Karla Stoedter, Chief
Branch 1
Division of Reactor Projects

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

Enclosure:
IR 05000373/2017001; 05000374/2017001

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Letter to Bryan C. Hanson from Karla Stoedter dated April 28, 2017

SUBJECT: LASALLE COUNTY STATION, UNITS 1 AND 2—NRC INTEGRATED INSPECTION REPORT 05000373/2017001 and 05000374/2017001

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	05000373; 05000374
License Nos:	NPF–11; NPF–18
Report No:	05000373/2017001; 05000374/2017001
Licensee:	Exelon Generation Company, LLC
Facility:	LaSalle County Station, Units 1 and 2
Location:	Marseilles, IL
Dates:	January 1 through March 31, 2017
Inspectors:	R. Ruiz, Senior Resident Inspector C. Hunt, Resident Inspector J. Cassidy, RIII Senior Health Physicist T. Go, RIII Health Physicist M. Holmberg, RIII Reactor Inspector M. Domke, RIII Reactor Inspector G. Hansen, RIII Sr. Emergency Preparedness Inspector R. Zuffa, (Illinois Emergency Management Agency), Resident Inspector L. Torres, (Illinois Emergency Management Agency) American Society of Mechanical Engineers Inspector
Approved by:	K. Stoedter, Chief Branch 1 Division of Reactor Projects

Enclosure

TABLE OF CONTENTS

SUMMARY 2

REPORT DETAILS 4

Summary of Plant Status 4

1. REACTOR SAFETY 5
- 1R04 Equipment Alignment (71111.04) 5
- 1R05 Fire Protection (71111.05) 6
- 1R08 Inservice Inspection Activities (71111.08) 6
- 1R11 Licensed Operator Requalification Program (71111.11) 10
- 1R12 Maintenance Effectiveness (71111.12) 11
- 1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13) 12
- 1R15 Operability Determinations and Functional Assessments (71111.15) 13
- 1R18 Plant Modifications (71111.18) 18
- 1R19 Post-Maintenance Testing (71111.19) 18
- 1R20 Outage Activities (71111.20) 19
- 1R22 Surveillance Testing (71111.22) 20
- 1EP2 Alert and Notification System Evaluation (71114.02) 22
- 1EP3 Emergency Response Organization Staffing and Augmentation System (71114.03) 22
- 1EP5 Maintenance of Emergency Preparedness (71114.05) 23

2. RADIATION SAFETY 23
- 2RS1 Radiological Hazard Assessment and Exposure Controls (71124.01) 23
- 2RS2 Occupational As-Low-As-Reasonably-Achievable Planning and Controls (71124.02) 27

4. OTHER ACTIVITIES 28
- 4OA1 Performance Indicator Verification (71151) 28
- 4OA2 Identification and Resolution of Problems (71152) 31
- 4OA3 Follow-Up of Events and Notices of Enforcement Discretion (71153) 32
- 4OA5 Other Activities 33
- 4OA6 Management Meetings 34
- 4OA7 Licensee-Identified Violations 34

SUPPLEMENTAL INFORMATION 1

Key Points of Contact 1

List of Items Opened, Closed, and Discussed 2

List of Documents Reviewed 3

List of Acronyms Used 1

SUMMARY

Inspection Report 05000373/2017001, 05000374/2017001; 01/01/2017 – 03/31/2017; LaSalle County Station, Units 1 and 2; Inservice Inspection Activities; Operability Determinations and Functionality Assessments; Licensee-Identified Violations

This report covers a 3–month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. Two Green findings were identified by the inspectors. The findings involved non-cited violations (NCVs) of the U.S. Nuclear Regulatory Commission (NRC) requirements. The significance of inspection findings is indicated by their color (i.e., greater than Green, or Green, White, Yellow, Red) and determined using Inspection Manual Chapter (IMC) 0609, “Significance Determination Process,” dated April 29, 2015. Cross-cutting aspects are determined using IMC 0310, “Aspects Within the Cross-Cutting Areas,” dated December 4, 2014. All violations of NRC requirements are dispositioned in accordance with the NRC’s Enforcement Policy, dated November 1, 2016. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG–1649, “Reactor Oversight Process,” Revision 6.

Cornerstone: Initiating Events

Green. The inspectors identified a finding of very-low safety significance with an associated NCV of Title 10 of the *Code of Federal Regulations* (CFR), Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” because the licensee failed to establish a procedure that ensured the American Society of Mechanical Engineers (ASME) Code VT–3 examination of the internal surface of valves or pumps occurred in the as-found condition (e.g., prior to repairs). Consequently, the licensee repaired internal damage to the 2B33–F067B valve prior to the Code VT–3 examination which potentially resulted in an ineffective VT–3 examination. The licensee entered this issue into their corrective action program (CAP) as Action Request (AR) 3972620, initiated actions to complete another VT–3 examination of valve 2B33–F067A or valve 2B33–F067B during the current outage and was evaluating additional controls for scheduling VT–3 internal examinations of pumps and valves.

The performance deficiency was determined to be more-than-minor because it affected the Initiating Events cornerstone attribute of equipment performance and adversely affected the cornerstone objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, if left uncorrected, this finding would lead to a more significant safety concern because it increased the likelihood of an operational challenge to the plant caused by a recirculation system line break initiated from undetected service-induced defects left in service inside pumps or valves as a result of ineffective VT–3 examinations. The finding was screened in accordance with Inspection Manual Chapter 0609, Appendix A, and the inspectors answered “No” to the applicable Phase 1 Initiating Events Screening question because the finding did not result in a reactor trip and/or loss of mitigation equipment relied upon to transition the plant from the onset of the trip to a stable shutdown condition. Therefore, this finding was determined to have very-low safety significance (Green). The finding had a cross-cutting aspect of Work Management in the Human Performance cross-cutting area because licensee managers failed to establish an adequate process of planning, controlling, and executing work activities such that nuclear safety is the overriding priority as evidenced by the lack of appropriately controls for scheduling the VT–3 internal examination of the 2B33–F067B valve (H.5). (Section 1R08.1)

Cornerstone: Mitigating Systems

Green. A finding of very low safety significance and an associated NCV of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was self-revealed for the licensee's failure to ensure that activities affecting quality were prescribed in a manner appropriate to the circumstances for the Unit 2, Division 3, diesel generator (DG) system. Specifically, the licensee's processes for the control and administration of preventive maintenance (ER–AA–200/WC–AA–120) failed to ensure that safety-related valve, 2E22–F319, the 2B DG cooling water strainer backwash valve, was replaced or refurbished at a frequency that would prevent corrosion-related stem-to-disc separation. The licensee entered this issue into their CAP as AR 1122320. Corrective actions planned and completed included replacement of the 2E22–F319 valve with a stainless steel design and performing an apparent cause evaluation of the degraded condition.

The performance deficiency was more than minor because it was associated with the Mitigating Systems Cornerstone attribute of equipment performance and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, the failure to perform preventive maintenance on the 2E22–F319 valve resulted in a degraded condition which adversely affected the reliability of the high pressure core spray system to respond to an initiating event. The inspectors evaluated the finding using the significance determination process in accordance with IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," Exhibit 2, dated June 19, 2012. The inspectors reviewed the Mitigating Systems screening questions in Exhibit 2 and answered "No" to question A.1, "If the finding is deficiency affecting the design or qualification of a mitigating SSC [structure, system, or component], does the SSC maintain its operability or functionality". The inspectors answered "Yes" to question A.2, "Does the finding represent a loss of system and/or function;" therefore, a detailed risk evaluation was required. The detailed risk evaluation determined that the finding screened as having very low safety significance (Green). This finding had a cross-cutting aspect in the area of Problem Identification and Resolution, because the organization failed to take effective corrective actions to address issues in a timely manner commensurate with their safety significance (P.3). (Section 1R15)

Violations of very low safety or security significance or Severity Level IV that were identified by the licensee have been reviewed by the NRC. Corrective actions taken or planned by the licensee have been entered into the licensee's CAP. These violations and CAP 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 13, 2017, the unit automatically scrammed from full power due to the turbine control valves' fast closure as a result of a turbine trip. The turbine tripped as a result of a main generator trip following the station's attempt to back-feed the Unit 2 unit auxiliary transformer from the grid. An unexpected failure occurred with the main generator output bus ducts, which led to the generator trip. The damaged components were repaired and the unit was restarted on February 17.

On February 17, however, during power ascension, the unit was manually scrammed due to an unexpected failure of the motor driven reactor feedwater pump feedwater regulating valve 1FW–005 control mechanism, which caused reactor water level to rise rapidly. The component was repaired and Unit 1 was restarted on February 19, reaching full-power on February 20.

On February 25, power was reduced to approximately 76 percent to perform a control rod-pattern adjustment and control rod testing. The unit returned to full power the next day and remained as such for the remainder of the inspection period.

Unit 2

The unit began the inspection period operating at full power. On January 7, 2017, the unit was down-powered to approximately 85 percent for a planned rod-pattern adjustment, and subsequently was returned to full-power at the conclusion.

On January 19, the unit began coasting down to the refueling outage at the end of the fuel cycle when the reactor was no longer capable of maintaining full-rated power. On January 23, the unit was manually scrammed from full-achievable power due to a main generator runback caused by a loss of stator water cooling. Stator water cooling flow was subsequently restored and the unit restarted on January 25, with full-achievable power being reached on January 28.

On February 5, Unit 2 shut down to begin refueling outage L2R16. On March 9, following completion of the outage, the reactor was restarted, and full power was achieved the next day. As planned, the unit was down-powered to approximately 80 percent on March 11 and 12 for rod-pattern adjustments. The unit was subsequently returned to full power on March 12, where it remained for the rest of inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

The inspectors performed partial system walkdowns of the following risk-significant systems:

- Unit 2, reactor core isolation cooling (RCIC);
- Unit 2 'B' residual heat removal (RHR); and
- Unit 2 'C' RHR.

The inspectors selected these systems based on their risk significance relative to the Reactor Safety Cornerstones at the time they were inspected. The inspectors attempted to identify any discrepancies that could impact the function of the system and, therefore, potentially increase risk. The inspectors reviewed applicable operating procedures, system diagrams, Updated Final Safety Analysis Report (UFSAR), Technical Specification (TS) requirements, outstanding work orders (WOs), Action Requests (ARs), and the impact of ongoing work activities on redundant trains of equipment to identify conditions that could have rendered the systems incapable of performing their intended functions. The inspectors also walked down accessible portions of the systems to verify system components and support equipment were aligned correctly and operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious deficiencies. The inspectors also verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the corrective action program (CAP) with the appropriate significance characterization. Documents reviewed are listed in the Attachment to this report.

These activities constituted three partial system walkdown samples as defined in Inspection Procedure (IP) 71111.04–05.

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

The inspectors conducted fire protection walkdowns which were focused on availability, accessibility, and the condition of firefighting equipment in the following risk-significant plant areas:

- fire zone 7B3 Unit 1 Division 1 standby diesel generator (DG) room 710';
- fire zone 7C3 Unit 1 Division 1 diesel fuel tank room 674';
- fire zone 7C6 Unit 1 Division 1 RHR service water pump room 674';
- fire zone 5B9 Unit 1 motor-driven reactor feed pump room;
- fire zone 3K Unit 2 steam tunnel 740'; and
- fire zone 3I3 Unit 2 RHR pump 'B' and 'C' cubicles.

The inspectors reviewed areas to assess if the licensee had implemented a fire protection program that adequately controlled combustibles and ignition sources within the plant, effectively maintained fire detection and suppression capability, maintained passive fire protection features in good material condition, and implemented adequate compensatory measures for out-of-service, degraded or inoperable fire protection equipment, systems, or features in accordance with the licensee's fire plan.

The inspectors selected fire areas based on their overall contribution to internal fire risk as documented in the plant's Individual Plant Examination of External Events with later additional insights, their potential to impact equipment which could initiate or mitigate a plant transient, or their impact on the plant's ability to respond to a security event. Using the documents listed in the Attachment to this report, the inspectors verified that fire hoses and extinguishers were in their designated locations and available for immediate use; that fire detectors and sprinklers were unobstructed; that transient material loading was within the analyzed limits; and fire doors, dampers, and penetration seals appeared to be in satisfactory condition. The inspectors also verified that minor issues identified during the inspection were entered into the licensee's CAP. Documents reviewed are listed in the Attachment to this report.

These activities constituted six quarterly fire protection inspection samples as defined in IP 71111.05–05.

b. Findings

No findings were identified.

1R08 Inservice Inspection Activities (71111.08)

From February 6 through February 16, 2017, the inspectors conducted a review of the implementation of the licensee's Inservice Inspection Program for monitoring degradation of the Unit 2 reactor coolant system, emergency feedwater systems, risk-significant piping and components and containment systems.

The inspections described in Sections 1R08.1 and 1R08.5 below constituted one inservice inspection sample as defined in IP 71111.08–05.

.1 Piping Systems Inservice Inspection

a. Inspection Scope

The inspectors observed the following Non-Destructive Examinations mandated by the ASME Section XI Code to evaluate compliance with the ASME Code Section XI and Section V requirements and if any indications and defects detected were detected, to determine if these were dispositioned in accordance with the ASME Code or an U.S. Nuclear Regulatory Commission (NRC) approved alternative requirement:

- ultrasonic examination (UT) of six main steam welds (IMS–2001–08; IMS–2001–20, IMS–2002–16, IMS–2003–13, IMS–2004–07 and IMS–2036–07);
- UT of reactor vessel shell longitudinal welds (LCS–2–BC and LCS–2–BA);
- automated UT of nozzle-to-shell weld GEL–1060–N7 on the Unit 2 reactor vessel; and
- magnetic particle examination of one reactor vessel head to flange weld (GEL–1060–AG).

The inspectors reviewed the following examination record with recordable indications accepted for continued service to determine if acceptance was in accordance with the ASME Code Section XI or an NRC approved alternative.

- UT examination of weld LP–2001–26A in the core spray system.

The inspectors reviewed the following pressure boundary welds completed for risk-significant systems during the last Unit 2 refueling outage to determine if the licensee applied the pre-service Non-Destructive Examination and acceptance criteria required by the construction Code and the ASME Code Section XI. Additionally, the inspectors reviewed the welding procedure specification and supporting weld procedure qualification records to determine if the weld procedures were qualified in accordance with the requirements of the Construction Code and the ASME Code Section IX:

- Internal welds No. 1A, 1B, 1C and 1D for valve 2B33–F067A in the reactor recirculation system, WO 1804383.

b. Findings

No findings were identified.

.2 Reactor Pressure Vessel Upper Head Penetration Inspection Activities – Not Applicable

.3 Boric Acid Corrosion Control – Not Applicable

.4 Steam Generator Tube Inspection Activities – Not Applicable

.5 <u>Identification and Resolution of Problems</u>

a. <u>Inspection Scope</u>

The inspectors performed a review of inservice inspection related problems entered into the licensee's CAP and conducted interviews with licensee staff to determine if:

- the licensee had established an appropriate threshold for identifying inservice inspection-related problems;
- the licensee had performed a root cause (if applicable) and taken appropriate corrective actions; and
- the licensee had evaluated operating experience and industry generic issues related to inservice inspection and pressure boundary integrity.

The inspectors performed these reviews to evaluate compliance with 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," requirements. The CAP documents reviewed by the inspectors are listed in the Attachment to this report.

b. <u>Findings</u>

<u>Inadequate Controls for ASME Code VT–3 Internal Examination of Pumps and Valves</u>

<u>Introduction</u>: The inspectors identified a finding of very low safety significance and an associated non-cited violation (NCV) of Title 10 of the *Code of Federal Regulations* (CFR), Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," because the licensee failed to establish a procedure that ensured the ASME Code VT–3 examination of the internal surface of valves or pumps occurred in the as-found condition (e.g., prior to repairs). Consequently, the licensee repaired internal damage to the 2B33–F067B valve prior to the Code VT–3 examination which potentially resulted in an ineffective VT–3 examination.

<u>Description</u>: The inspectors reviewed the licensee's corrective actions implemented under WO 1614962, "2B33–F067B Indicated Dual upon Valve Closure." Under this WO, the licensee disassembled and conducted internal repairs to the recirculation pump discharge valve 2B33–F067B and also performed a VT–3 examination of the interior surfaces of this valve to fulfill the ASME Code Section XI, Table IWB–2500 inspection category B–M–2 requirements. No rejectable conditions were identified during the VT–3 examination of valve 2B33–F067B completed on February 25, 2013. This examination was performed one day after the repairs were made to correct damage to the integral valve guides on the 2B33–F067B valve body and the inspectors were concerned that this failure to conduct an as-found VT–3 examination rendered the examination ineffective.

In accordance with the Licensee Procedure ER–AA–335–017, "Visual Examination of Pump and Valve Internals," the VT–3 examination is done to identify service induced degradation such as erosion, cracking, galling, physical damage, wear or debris. The inspectors reviewed records of the repairs and pictures taken of the internal valve surfaces during the 2013 repair work under WO 1614962 and determined that service induced degradation was present on the interior surfaces of this valve. Specifically, the licensee identified, then removed, linear indications (e.g., potential cracks) with a grinder and completed weld repairs on the valve guide attachment welds one day prior to the VT–3 examination. If the VT–3 examination had been implemented prior to these repairs and identified rejectable conditions (e.g., cracking or excessive wear), the ASME Code Section XI would have required that the licensee perform an additional internal VT–3 examination of the 2B33–F067A valve. However, this did not occur because the post repair VT–3 internal examination did not identify any rejectable indications. The failure to expand the VT–3 examination to include internal examination of the 2B33–F067A valve in 2013 resulted in a missed opportunity to identify and correct degraded conditions within this valve which subsequently failed to operate during the 2015 refueling outage due to internal service induced damage. This missed opportunity (inspect the 2B33–F067A valve) was identified by the licensee during a root cause investigation completed in 2015 (reference AR 2478819), but the licensee did not recognize that this missed opportunity may have been the direct result of an inadequate VT–3 examination on the 2B33–F067B valve. The lack of a procedure to ensure that VT–3 internal examinations of pumps or valves occurred in the as-found condition, could result in a failure of the licensee to expand the scope of VT–3 examinations and identify the extent of degradation prior to component failure.

Analysis: The failure to establish a procedure that ensured the ASME Code VT–3 examination of the internal surface of valves or pumps occurred in the as-found condition (e.g. prior to repairs) was contrary to 10 CFR 50 Appendix B, Criterion V and a performance deficiency. The inspectors determined that the performance deficiency was more than minor in accordance with Inspection Manual Chapter (IMC) 0612, Appendix B, "Issue Screening," because it affected the Initiating Events cornerstone attribute of equipment performance and adversely affected the cornerstone objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, if left uncorrected, this finding would lead to a more significant safety concern because it increased the likelihood of a an operational challenge to the plant caused by a recirculation system line break initiated from undetected service induced defects left in service inside pumps or valves as a result of ineffective VT–3 examinations.

The inspectors evaluated the finding in accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," and Appendix A, "The Significance Determination Process for Findings at Power," Exhibit 1, "Initiating Events Screening Questions." Under Part B, "Transient Initiators," of the Exhibit 1 screening questions, the inspectors answered "No" because the finding did not result in a reactor trip and/or loss of mitigation equipment relied upon to transition the plant from the onset of the trip to a stable shutdown condition and therefore this finding screened as having very low safety significance (Green).

This finding was the result of a performance deficiency that occurred more than three years ago, however no site barriers or controls existed to preclude this finding from recurring. Therefore, the inspectors concluded that this finding reflected present performance. The finding had a cross-cutting aspect of Work Management in the Human Performance cross-cutting area, because licensee managers failed to establish an adequate process of planning, controlling, and executing work activities such that nuclear safety is the overriding priority as evidenced by the lack of appropriate controls for scheduling the VT–3 internal examination of the 2B33–F067B valve (H.5).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances.

Contrary to these requirements, as of February 16, 2017, for an activity affecting quality (scheduling of ASME Code required VT–3 internal examination of pumps and valves), the licensee failed to prescribe a procedure of a type appropriate to the circumstance. Specifically, a procedure had not been established to ensure the ASME Code VT–3 examination of the internal surface of valves or pumps occurred in the as-found condition (e.g., prior to repairs). The licensee entered this issue into the CAP system as AR 3972620, initiated actions to complete another VT–3 examination of the valve 2B33–F067A or valve 2B33–F067B during the current outage and was evaluating additional controls for scheduling VT–3 internal examinations of pumps and valves. The inspectors did not have concerns for operability of 2B33–F067B based upon the additional valve repairs that had been completed during the 2015 refueling outage.

Because this violation was of very-low safety significance, and entered into the CAP (AR 3972620), this violation is being treated as an NCV, consistent with Section 2.3.2.a of the NRC Enforcement Policy. **(NCV 05000373/2017001–01; 05000374/2017001–01; Inadequate Controls for ASME Code VT–3 Internal Examination of Pumps and Valves)**

1R11 Licensed Operator Requalification Program (71111.11)

.1 Resident Inspector Quarterly Review of Licensed Operator Requalification (71111.11Q)

a. Inspection Scope

On March 22, 2017, the inspectors observed a crew of licensed operators in the plant's simulator during licensed operator requalification training. The inspectors verified that operator performance was adequate, evaluators were identifying and documenting crew performance problems, and that training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

- licensed operator performance;
- crew's clarity and formality of communications;
- ability to take timely actions in the conservative direction;
- prioritization, interpretation, and verification of annunciator alarms;
- correct use and implementation of abnormal and emergency procedures;
- control board manipulations;
- oversight and direction from supervisors; and
- ability to identify and implement appropriate TS actions and Emergency Plan actions and notifications.

The crew's performance in these areas was compared to pre-established operator action expectations and successful critical task completion requirements. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one quarterly licensed operator requalification program simulator sample as defined in IP 71111.11–05.

b. Findings

No findings were identified.

.2 Resident Inspector Quarterly Observation During Periods of Heightened Activity or Risk (71111.11Q)

a. Inspection Scope

On February 15, 2017, the inspectors observed operator activities in the control room during a Unit 1 restart. This was an activity that required heightened awareness or was related to increased risk. The inspectors evaluated the following areas:

- licensed operator performance;
- crew's clarity and formality of communications;
- ability to take timely actions in the conservative direction;
- prioritization, interpretation, and verification of annunciator alarms (if applicable);
- correct use and implementation of procedures;
- control board (or equipment) manipulations;
- oversight and direction from supervisors; and
- ability to identify and implement appropriate TS actions and Emergency Plan actions and notifications (if applicable).

The performance in these areas was compared to pre-established operator action expectations, procedural compliance and task completion requirements. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one quarterly licensed operator heightened activity/risk sample as defined in IP 71111.11–05.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations

a. Inspection Scope

The inspectors evaluated degraded performance issues involving the following risk-significant system:

- auxiliary power system—480V and above.

The inspectors reviewed events such as where ineffective equipment maintenance had resulted in valid or invalid automatic actuations of engineered safeguards systems and independently verified the licensee's actions to address system performance or condition problems in terms of the following:

- implementing appropriate work practices;
- identifying and addressing common cause failures;

- scoping of systems in accordance with 10 CFR 50.65(b) of the maintenance rule;
- characterizing system reliability issues for performance;
- charging unavailability for performance;
- trending key parameters for condition monitoring;
- ensuring 10 CFR 50.65(a)(1) or (a)(2) classification or re-classification; and
- verifying appropriate performance criteria for structures, systems, and components (SSCs)/functions classified as (a)(2), or appropriate and adequate goals and corrective actions for systems classified as (a)(1).

The inspectors performed a quality review for the auxiliary power 480V and above, as discussed in IP 71111.12, Section 02.02.

The inspectors assessed performance issues with respect to the reliability, availability, and condition monitoring of the system. In addition, the inspectors verified maintenance effectiveness issues were entered into the CAP with the appropriate significance characterization. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one quarterly maintenance effectiveness sample as defined in IP 71111.12–05.

b. Findings

No findings were identified

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

.1 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

The inspectors reviewed the licensee's evaluation and management of plant risk for the maintenance and emergent work activities affecting risk-significant and safety-related equipment listed below to verify that the appropriate risk assessments were performed prior to removing equipment for work:

- Unit 2 stator cooling system restoration;
- Unit 2 B DG cooling water strainer backwash valve;
- Unit 2 Division II direct current work window; and
- valve 2FC–017 stuck open.

These activities were selected based on their potential risk significance relative to the Reactor Safety Cornerstones. As applicable for each activity, the inspectors verified that risk assessments were performed as required by 10 CFR 50.65(a)(4) and were accurate and complete. When emergent work was performed, the inspectors verified that the plant risk was promptly reassessed and managed. The inspectors reviewed the scope of maintenance work, discussed the results of the assessment with the licensee's probabilistic risk analyst or shift technical advisor, and verified plant conditions were consistent with the risk assessment. The inspectors also reviewed TS requirements and walked down portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid and applicable requirements were met.

Documents reviewed during this inspection are listed in the Attachment to this report.

These maintenance risk assessments and emergent work control activities constituted four samples as defined in IP 71111.13–05.

b. Findings

No findings were identified.

1R15 Operability Determinations and Functional Assessments (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- Unit 2 B DG cooling water strainer backwash valve; and
- plant barrier impairment requirements not met for high energy line break doors.

The inspectors selected these potential operability issues based on the risk significance of the associated components and systems. The inspectors evaluated the technical adequacy of the evaluations to ensure that TS operability was properly justified and the subject component or system remained available such that no unrecognized increase in risk occurred. The inspectors compared the operability and design criteria in the appropriate sections of the TS and Updated Final Safety Analysis Report (UFSAR) to the licensee's evaluations to determine whether the components or systems were operable. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures in place would function as intended and were properly controlled. The inspectors determined, where appropriate, compliance with bounding limitations associated with the evaluations. Additionally, the inspectors reviewed a sampling of CAP documents to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations. Documents reviewed are listed in the Attachment to this report.

This operability inspection constituted two samples as defined in IP 71111.15–05.

b. Findings

Failure to Perform Preventive Maintenance Resulted in Stem-to-Disc Separation of Safety-Related Valve

Introduction: A finding of very low safety significance and an associated NCV of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was self-revealed for the licensee's failure to ensure that activities affecting quality were prescribed in a manner appropriate to the circumstances for the Unit 2 Division 3 DG system. Specifically, the licensee's processes for the control and administration of preventive maintenance (ER–AA–200/WC–AA–120) failed to ensure that the safety-related 2E22–F319, 2B DG cooling water strainer backwash valve, was replaced or refurbished at a frequency that would prevent corrosion-related stem-to-disc separation.

Description: On January 30, 2017, during the performance of surveillance procedure LOS–DG–M3, Unit 2 "B" DG operability test, it was identified that the 2E22–F319, 2B DG cooling water strainer backwash valve failed to open. The licensee declared the DG cooling water system and its supported systems inoperable (high pressure core spray (HPCS), and Division 3 DG) per TS 3.7.2, and made the appropriate emergency notification system notification for a condition that could have prevented the fulfillment of a safety function. Troubleshooting revealed stem-to-disc separation and the internals were subsequently replaced with stainless steel components per WO 818621. The system was successfully returned to service on February 2, 2017.

The inspectors reviewed LaSalle-specific historical documents related to similar such valve failures and noted that identical stem-to-disc separations had occurred on multiple safety-related, raw-water, system valves going back to 1996. Following the first similar valve failure in 1996, RCR 373–200–96.00153.00 was performed and identified the 2E22–F319 valve, specifically, as being susceptible to stem-to-disc separation due to the “T–Slot” stem/disc interface.

Subsequently, the licensee received an acceptance criterion from the valve manufacturer for the critical parameter of the maximum amount of “free play” or “T–Gap” of the stem-to-disc T–connection by which the licensee could have reasonable assurance that a separation would not occur. A value of 0.5 inches was provided as a threshold for the licensee to initiate replacement.

Additionally, to prevent the problem from recurring, the licensee’s original corrective actions coming out of the 1996 root cause evaluation included creation of a 10–year preventative maintenance (PM) activity to inspect, replace, or refurbish the valve. The PM frequency was chosen based on the previous failure history of carbon steel discs at LaSalle, plus margin.

In 2005, the PM frequency was extended from 10 years to 14 years, per Service Request #00037852. The only justification given was “Based on work history and improvements to water chemistry.”

In 2014, the PM frequency was extended from 14 years to 15 years, per Service Request #00084595, based on a “T–Gap” measurement of 0.375 inches being less than the manufacturer’s acceptance criteria.

In 2015, the PM frequency was extended from 15 years to 19 years, per Service Request #00090111, using the exact same analysis as the 2014 extension with no new T–Gap measurement taken or additional analysis on valve wear or corrosion rates. The inspectors further noted that this valve had not been opened and visually inspected since 1996.

The 19–year PM was scheduled for November 2017, but the valve failed prior to that PM’s performance.

The licensee performed an apparent cause evaluation and determined that the failure occurred due to erosion/corrosion of the carbon steel valve internals being subjected to the raw-water conditions of the core standby cooling system (CSCS) system over time. Other causes documented in the apparent cause evaluation included that preventive maintenance to replace the valve was extended beyond the 14–year life of the valve and T–Gap measurements used to determine valve health did not take into account lateral erosion/corrosion of the component.

Analysis: The failure of the preventive maintenance (PM) program, ER–AA–200/WC–AA–120 (an activity affecting quality), to drive the performance of preventive maintenance on the Unit 2 E22–F319 valve on an interval that would prevent stem-to-disc separation due to a well-known failure mechanism (corrosion/erosion of carbon steel components in raw-water systems) was not in accordance with the requirements of 10 CFR 50, Appendix B, Criterion V, and was a performance deficiency. Specifically, the multiple extensions of PM due-dates with insufficient technical justification allowed the PM program to be implemented in a manner that was inappropriate to the circumstances.

In accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," dated September 7, 2012, the inspectors determined that the performance deficiency was more than minor, and thus a finding because it was associated with the Mitigating Systems cornerstone attribute of equipment performance and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the failure to perform preventive maintenance on the 2E22–F319 valve resulted in a degraded condition which adversely affected the reliability of the HPCS system to respond to an initiating event. The inspectors evaluated the finding using the significance determination process in accordance with IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," Exhibit 2, dated June 19, 2012. The inspectors reviewed the Mitigating Systems screening questions in Exhibit 2 and answered "No" to question A.1, "If the finding is a deficiency affecting the design or qualification of a mitigating SSC, does the SSC maintain its operability or functionality"? The inspectors answered "Yes" to question A.2, "Does the finding represent a loss of system and/or function"? Therefore, a detailed risk evaluation was required.

To evaluate the risk significance of the finding, a Senior Reactor Analyst used the LaSalle Standardized Plant Analysis Risk (SPAR) Model, Version 8.24 and Systems Analysis Programs for Hands-On Integrated Reliability Evaluations (SAPHIRE), Version 8.1.4.

The failure of the Division 3 DG Cooling Water Strainer Backwash Valve 2E22–F319 was evaluated as a failure of HPCS and the failure of the Division 3 HPCS DG in the LaSalle SPAR model. Since the time of failure of the valve is not known, the exposure time used the "T/2" plus repair time methodology as described in the Risk Assessment Standardization Project handbook. The last successful test of the valve was on December 29, 2016, and the failure of the valve occurred on January 30, 2017. This is a time period of 32 days, so a "T/2" evaluation yields a time of 16 days for when the valve was failed before discovery. The valve was repaired on February 2, 2017, and so the repair time was 3 days. The exposure time is therefore calculated to be 19 days (16 days + 3 days = 19 days). Using the LaSalle SPAR model, the delta core damage frequency (ΔCDF) for a failure of HPCS and the HPCS DG for 16 days was determined to be 6.0E–7/year for internal events. The dominant core damage sequence was a Loss of Offsite Power (LOOP)–Weather Related initiating event with a failure of emergency power, HPCS, manual reactor depressurization, and failure to recover offsite power or emergency DG power in seven (7) hours. The three (3) days of repair time yielded an additional ΔCDF of 1.2E–7/year. The internal delta risk was thus the sum of these two values or a ΔCDF of 7.2E–7/year (i.e., 6.0E–7/year + 1.2E–7/year = 7.2E–7/year).

Since the ΔCDF for internal events was greater than 1E–7/year, an evaluation was made of the delta risk for external events (fire and seismic).

FIRE Risk

A rough estimate of the fire risk contribution was obtained using information from the LaSalle Plant Partitioning and Fire Ignition Frequency Development Notebook (LS–PRA–21.02), Revision 1. The Fire Ignition Frequencies (FIFs) for the Fire Compartments for LaSalle are given in this Notebook. A failure of RCIC in conjunction with a failure of HPCS was deemed to be a risk significant fire scenario. By summing the FIFs for the Fire Compartments associated with reactor core isolation cooling (RCIC) [except for the Main Control Board (MCB)], a FIF value of 7.50E–4/year for Unit 2 was obtained.

Since the additional equipment failures that would occur for the various affected Fire Compartments are not specified in the Notebook, the failure of the main feedwater system was assumed to provide limiting scenarios based on review of the LaSalle SPAR model Transient event tree. Using the LaSalle SPAR model, the conditional core damage probability (CCDP) of a transient initiating event with loss of HPCS and main feedwater and a failure of RCIC was 5.00E–4. The nominal CCDP without the RCIC failure was 2.48E–7. Thus, the delta (change in) ΔCCDP is 5.00E–4.

The ΔCDF for the Fire Compartments that contain HPCS equipment (except for the MCB) for an Exposure Time (ET) of 19 days is:

ΔCDF HPCS (except MCB) = [FIF] x [ΔCCDP] x [ET]

= [7.50E–4/year] x [5.00E–4] x [19 days/365 days]

= 2.0E–8/year

Fire in Main Control Room

There is an additional delta risk associated with a fire in the Main Control Room. From the LaSalle Unit 2 Fire Scenario Report (LS–PSA–021.05), Revision 0, fire scenarios D1, D4, and D5 were evaluated for risk significance. The failure of the main feedwater system was assumed to provide limiting scenarios based on review of the LaSalle SPAR model event trees. The result was a ΔCDF HPCS–MCB of 5.1E–8/year for these fire scenarios for an Exposure Time of 19 days.

Total Estimated Risk from Fires

The total estimated risk from fires is the sum of the risk from the above fire initiating events:

ΔCDF Fire = ΔCDFHPCS (except MCB) + ΔCDFHPCS–MCB

= 2.0E–8/year + 5.1E–8/year

= 7.1E–8/year

SEISMIC Risk

The seismic risk was evaluated for a failure of HPCS and the Division 3 HPCS DG. The frequency of a seismically-induced LOOP for LaSalle is given as 1.13E–4/year from the Risk Assessment Standardization Project handbook. Using the LaSalle SPAR model, a ΔCCDP of 5.8E–3 was obtained for a LOOP without offsite power recovery. For an ET of 19 days, the ΔCDF seismic is obtained as:

ΔCDF seismic = [LOOP frequency] x [ΔCCDP] x [ET]

= (1.13E–4/year) x (5.8E–3) x (19 days/365 days)

= 3.4E–8/year

Total External Risk

The total external risk is thus 1.1E–7/year
(i.e., 7.1E–8/year + 3.4E–8/year = 1.1E–7/year).

Total Internal plus External Risk

The total internal plus external risk is thus 8.3E–7/year, or,
7.2E–7/year + 1.1E–7/year = 8.3E–7/year.

Evaluation of Delta Large Early Release Frequency

Since the ΔCDF was greater than 1E–7/year, an evaluation of the delta in large early release frequency (ΔLERF) was performed per IMC 0609, Appendix H, Containment Integrity Significance Determination Process. A LERF Factor of 0.3 is used for a Mark II containment similar to LaSalle for sequences with a failure of reactor depressurization. Using this LERF Factor, the result was a ΔLERF of less than 1E–8/yr.

Based on the Detailed Risk Evaluation, the Senior Reactor Analyst determined that the finding was of very low safety significance (Green).

The inspectors concluded that the cause of this finding was associated with the cross-cutting area of Problem Identification and Resolution, specifically in the aspect of Resolution (P.3), because the organization failed to take effective corrective actions to address issues in a timely manner commensurate with their safety significance.

Enforcement: Title 10 CFR, Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," states, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstance and shall be accomplished in accordance with these instructions, procedures, or drawings.

Contrary to the above, from May 15, 2005, to January 30, 2017, the licensee failed to prescribe activities affecting quality of a type appropriate to the circumstances for governing the preventive maintenance of the Unit 2E22–F319 valve, a safety-related component. Specifically, the licensee's processes for the control and administration of preventive maintenance failed to ensure that the 2E22–F319 valve internals were replaced or refurbished on an interval that would prevent stem-to-disc separation from adversely affecting system operability. As a result, the well-known failure mechanism of corrosion/erosion of carbon steel components in raw-water systems caused the 2E22–F319 valve to fail.

As corrective actions, the licensee replaced the 2E22–F319 valve with a completely new stainless steel model, performed an apparent cause evaluation to further explore the causal factors. Because this violation was of very low safety significance and the issue was entered in into the licensee's CAP as Action Request (AR) 1122320, this violation is being treated as a NCV, consistent with Section 2.3.2.a of the Enforcement Policy. **(NCV 05000373/2017001–02, Failure to Perform Preventive Maintenance Resulted in Stem-to-Disc Separation of Safety-Related Valve)**

1R18 Plant Modifications (71111.18)

.1 Plant Modifications

a. Inspection Scope

The inspectors reviewed the jet pump plug seismic qualification of new pads permanent modification. They reviewed the configuration changes and associated 10 CFR 50.59 safety evaluation screening against the design basis, the UFSAR, and the TS, as applicable, to verify that the modification did not affect the operability or availability of the affected system. The inspectors, as applicable, observed ongoing and completed work activities to ensure that the modifications were installed as directed and consistent with the design control documents; the modifications operated as expected; post-modification testing adequately demonstrated continued system operability, availability, and reliability; and that operation of the modifications did not impact the operability of any interfacing systems. As applicable, the inspectors verified that relevant procedure, design, and licensing documents were properly updated. Lastly, the inspectors discussed the plant modification with operations, engineering, and training personnel to ensure that the individuals were aware of how the operation with the plant modification in place could impact overall plant performance. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one permanent plant modification sample as defined in IP 71111.18–05.

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19)

.1 Post-Maintenance Testing

a. Inspection Scope

The inspectors reviewed the following post-maintenance testing (PMT) activities to verify that procedures and test activities were adequate to ensure system operability and functional capability:

- Unit 2 A DG run after motor operating potentiometer replacement;
- Unit 2 stator water cooling restoration following troubleshooting;
- LOS–DG–SR7 after 2B DG cooling water strainer backwash valve repair; and
- 2E12–F031B residual heat removal (RHR) B pump discharge check valve testing following repair.

These activities were selected based upon the SSC's ability to impact risk. The inspectors evaluated these activities for the following (as applicable): the effect of testing on the plant had been adequately addressed; testing was adequate for the maintenance performed; acceptance criteria were clear and demonstrated operational readiness; test instrumentation was appropriate; tests were performed as written in accordance with properly reviewed and approved procedures; equipment was returned to its operational status following testing (temporary modifications or jumpers required for test performance were properly removed after test completion); and test documentation was properly evaluated. The inspectors evaluated the activities against TSs, the UFSAR, 10 CFR 50 requirements, licensee procedures and various U.S. Nuclear Regulatory Commission (NRC) generic communications to ensure that the test results adequately ensured that the equipment met the licensing basis and design requirements. In addition, the inspectors reviewed CAP documents associated with post-maintenance tests to determine whether the licensee was identifying problems and entering them in the CAP and that the problems were being corrected commensurate with their importance to safety. Documents reviewed are listed in the Attachment to this report.

This inspection constituted four post-maintenance testing samples as defined in IP 71111.19–05.

b. Findings

No findings were identified.

1R20 Outage Activities (71111.20)

.1 Refueling Outage Activities

a. Inspection Scope

The inspectors reviewed the outage safety plan and contingency plans for the Unit 2 refueling outage, L2R16, conducted February 6 through March 8, 2017, to confirm that the licensee had appropriately considered risk, industry experience and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth. During the refueling outage, the inspectors observed portions of the shutdown and cooldown processes and monitored licensee controls over the outage activities listed below:

- licensee configuration management, including maintenance of defense-in-depth commensurate with the outage safety plan for key safety functions and compliance with the applicable TS when taking equipment out of service;
- implementation of clearance activities and confirmation that tags were properly hung and equipment appropriately configured to safely support the work or testing;

- installation and configuration of reactor coolant pressure, level, and temperature instruments to provide accurate indication, accounting for instrument error;
- controls over the status and configuration of electrical systems to ensure that TS and outage safety plan requirements were met, and controls over switchyard activities;
- monitoring of decay heat removal processes, systems, and components;
- controls to ensure that outage work was not impacting the ability of the operators to operate the spent fuel pool cooling system;
- reactor water inventory controls including flow paths, configurations, and alternative means for inventory addition, and controls to prevent inventory loss;
- controls over activities that could affect reactivity;
- maintenance of secondary containment as required by TS;
- licensee fatigue management, as required by 10 CFR 26, Subpart I;
- refueling activities, including fuel handling and sipping to detect fuel assembly leakage;
- startup and ascension to full power operation, tracking of startup prerequisites, walkdown of the drywell (primary containment) to verify that debris had not been left which could block emergency core cooling system suction strainers, and reactor physics testing; and
- licensee identification and resolution of problems related to refueling outage activities.

Documents reviewed are listed in the Attachment to this report.

This inspection constituted one refueling outage sample as defined in IP 71111.20–05.

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22)

.1 Surveillance Testing

a. Inspection Scope

The inspectors reviewed the test results for the following activities to determine whether risk-significant systems and equipment were capable of performing their intended safety function and to verify testing was conducted in accordance with applicable procedural and TS requirements:

- LOS–DG–201 Unit 2 Common DG start and load acceptance (routine);
- LOS–DG–209 Unit 2 Division I response time testing (routine);
- LOS–HP–Q1 HPCS system inservice test (routine);
- LOS–R1–Q3 RCIC system pump operability test and 2E51–F030 check valve (IST); and
- LOS–CS–Q1 secondary containment damper operations test (CIV).

The inspectors observed in-plant activities and reviewed procedures and associated records to determine the following:

- did preconditioning occur;
- the effects of the testing were adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- acceptance criteria were clearly stated, demonstrated operational readiness, and were consistent with the system design basis;
- plant equipment calibration was correct, accurate, and properly documented;
- as-left setpoints were within required ranges; and the calibration frequency was in accordance with TSs, the UFSAR, procedures, and applicable commitments;
- measuring and test equipment calibration was current;
- test equipment was used within the required range and accuracy; applicable prerequisites described in the test procedures were satisfied;
- test frequencies met TS requirements to demonstrate operability and reliability; tests were performed in accordance with the test procedures and other applicable procedures; jumpers and lifted leads were controlled and restored where used;
- test data and results were accurate, complete, within limits, and valid;
- test equipment was removed after testing;
- where applicable for inservice testing activities, testing was performed in accordance with the applicable version of Section XI, American Society of Mechanical Engineers code, and reference values were consistent with the system design basis;
- where applicable, test results not meeting acceptance criteria were addressed with an adequate operability evaluation or the system or component was declared inoperable;
- where applicable for safety-related instrument control surveillance tests, reference setting data were accurately incorporated in the test procedure;
- where applicable, actual conditions encountering high resistance electrical contacts were such that the intended safety function could still be accomplished;
- prior procedure changes had not provided an opportunity to identify problems encountered during the performance of the surveillance or calibration test;
- equipment was returned to a position or status required to support the performance of its safety functions; and
- all problems identified during the testing were appropriately documented and dispositioned in the CAP.

Documents reviewed are listed in the Attachment to this report.

This inspection constituted three routine surveillance testing samples, one in-service test sample, and one containment isolation valve sample as defined in IP 71111.22, Sections–02 and–05.

b. Findings

No findings were identified.

Cornerstone: Emergency Preparedness

1EP2 Alert and Notification System Evaluation (71114.02)

.1 Alert and Notification System Evaluation

a. Inspection Scope

The inspectors reviewed documents, and conducted discussions with Emergency Preparedness (EP) staff and management regarding the operation, maintenance, and periodic testing of the back-up and primary Alert and Notification System (ANS) in LaSalle County Station's plume pathway Emergency Planning Zone. The inspectors reviewed monthly trend reports and the daily and monthly operability records from March 2015 through March 2017. Information gathered during document reviews, and interviews was used to determine whether the ANS equipment was maintained and tested in accordance with Emergency Plan commitments and procedures. Documents reviewed are listed in the Attachment to this report.

This ANS inspection constituted one sample as defined in IP 71114.02

b. Findings

No findings were identified.

1EP3 Emergency Response Organization Staffing and Augmentation System (71114.03)

.1 Emergency Response Organization Staffing and Augmentation System

a. Inspection Scope

The inspectors reviewed and discussed with plant EP management and staff the emergency plan commitments and procedures that addressed the primary and alternate methods of initiating an Emergency Response Organization (ERO) activation to augment the on-shift staff as well as the provisions for maintaining the plant's ERO team and qualification lists. The inspectors reviewed reports and a sample of CAP records of unannounced off-hour augmentation drills and call-in tests, which were conducted from March 2015 through March 2017, to determine the adequacy of the drill critiques and associated corrective actions. The inspectors also reviewed a sample of the training records of approximately fifteen ERO personnel, who were assigned to key and support positions, to determine the status of their training as it related to their assigned ERO positions. Documents reviewed are listed in the Attachment to this report.

This ERO augmentation testing inspection constituted one sample as defined in IP 71114.03.

b. Findings

No findings were identified.

1EP5 Maintenance of Emergency Preparedness (71114.05)

.1 Maintenance of Emergency Preparedness

a. Inspection Scope

The inspectors reviewed a sample of nuclear oversight staff's audits of the EP Program to determine whether these independent assessments met the requirements of 10 CFR 50.54(t). The inspectors also reviewed critique reports and samples of CAP records associated with the 2016 biennial exercise, as well as various EP drills conducted in 2015, 2016, and 2017 to determine whether the licensee fulfilled drill commitments and to evaluate the licensee's efforts to identify, track, and resolve issues identified during these activities. The inspectors reviewed a sample of EP items and corrective actions related to the licensee's EP Program and activities to determine whether corrective actions were completed, in accordance with the site's CAP. Documents reviewed are listed in the Attachment to this report.

This correction of EP weaknesses and deficiencies inspection constituted one sample as defined in IP 71114.05.

b. Findings

No findings were identified.

2. RADIATION SAFETY

2RS1 Radiological Hazard Assessment and Exposure Controls (71124.01)

.1 Radiological Hazard Assessment (02.02)

a. Inspection Scope

The inspectors assessed the licensee's current and historic isotopic mix, including alpha emitters and other hard-to-detect radionuclides. The inspectors evaluated whether survey protocols were reasonable to identify the magnitude and extent of the radiological hazards.

The inspectors determined if there have been changes to plant operations since the last inspection that may have resulted in a significant new radiological hazard for onsite individuals. The inspectors evaluated whether the licensee assessed the potential impact of these changes and implemented periodic monitoring, as appropriate, to detect and quantify the radiological hazard. The inspectors reviewed the last two radiological surveys from selected plant areas and evaluated whether the thoroughness and frequency of the surveys were appropriate for the given radiological hazard.

The inspectors conducted walkdowns of the facility, including radioactive waste processing, storage, and handling areas to evaluate material conditions and performed independent radiation measurements as needed to verify conditions were consistent with documented radiation surveys.

The inspectors assessed the adequacy of pre-work surveys for select radiologically risk-significant work activities.

The inspectors evaluated the Radiological Survey Program to determine if hazards were properly identified. The inspectors discussed procedures, equipment, and performance of surveys with radiation protection staff and assessed whether technicians were knowledgeable about when and how to survey areas for various types of radiological hazards.

The inspectors reviewed work in potential airborne areas to assess whether air samples were being taken appropriately for their intended purpose and reviewed various survey records to assess whether the samples were collected and analyzed appropriately. The inspectors also reviewed the licensee's program for monitoring contamination which has the potential to become airborne.

These inspection activities constituted one sample as defined in IP 71124.01–05.

b. Findings

No findings were identified.

.2 Instructions to Workers (02.03)

a. Inspection Scope

The inspectors reviewed select radiation work permits used to access high radiation areas and evaluated the specified work control instructions or control barriers. The inspectors also assessed whether workers where made aware of the work instructions and area dose rates.

The inspectors reviewed electronic alarming dosimeter dose and dose rate alarm setpoint methodology. For selected electronic alarming dosimeter occurrences, the inspectors assessed the worker's response to the alarm, the licensee's evaluation of the alarm, and any follow-up investigations.

The inspectors reviewed the licensee's methods for informing workers of changes in plant operations or radiological conditions that could significantly impact their occupational dose.

The inspectors reviewed the labeling of select containers of licensed radioactive material that could cause unplanned or inadvertent exposure to workers.

These inspection activities constituted one sample as defined in IP 71124.01–05.

b. Findings

No findings were identified.

.3 Contamination and Radioactive Material Control (02.04)

a. Inspection Scope

The inspectors observed locations where the licensee monitors material leaving the radiologically controlled area and assessed the methods used for control, survey, and release of material from these areas. As available, the inspectors observed health physics personnel surveying and releasing material for unrestricted use.

The inspectors observed workers leaving the radiologically controlled area and assessed their use of tool and personal contamination monitors and reviewed the licensee's criterial for use of the monitors.

The inspectors assessed whether instrumentation was used at its typical sensitivity levels based on appropriate counting parameters or whether the licensee had established a de facto release limit.

The inspectors selected several sealed sources from the licensee's inventory records and assessed whether the sources were accounted for and verified to be intact. The inspectors also evaluated whether any transactions, since the last inspection, involving nationally tracked sources were reported in accordance with 10 CFR 20.2207.

These inspection activities constituted one sample as defined in IP 71124.01–05.

b. Findings

No findings were identified.

.4 Radiological Hazards Control and Work Coverage (02.05)

a. Inspection Scope

The inspectors evaluated ambient radiological conditions during tours of the facility. The inspectors assessed whether the conditions were consistent with applicable posted surveys, radiation work permits, and worker briefings.

The inspectors evaluated the adequacy of radiological controls, such as required surveys, radiation protection job coverage, and contamination controls. The inspectors evaluated the licensee's use of electronic alarming dosimeters in high noise areas as high radiation area monitoring devices.

The inspectors assessed whether radiation monitoring devices were placed on the individual's body consistent with licensee procedures. The inspectors assessed whether the dosimeter was placed in the location of highest expected dose or that the licensee properly employed a U.S. Nuclear Regulatory Commission approved method of determining effective dose equivalent.

The inspectors reviewed the application of dosimetry to effectively monitor exposure to personnel in work areas with significant dose rate gradients.

For select airborne area radiation work permits, the inspectors reviewed airborne radioactivity controls and monitoring, the potential for significant airborne levels, containment barrier integrity, and temporary filtered ventilation system operation.

The inspectors examined the licensee's physical and programmatic controls for highly activated or contaminated materials stored within pools and assessed whether appropriate controls were in place to preclude inadvertent removal of these materials from the pool.

These inspection activities constituted one sample as defined in IP 71124.01–05.

b. Findings

No findings were identified.

.5 High Radiation Area and Very High Radiation Area Controls (02.06)

a. Inspection Scope

The inspectors observed posting and physical controls for high radiation areas and very high radiation areas to assess adequacy.

The inspectors conducted a selective inspection of posting and physical controls for high radiation areas and very high radiation areas to assess conformance with performance indicators.

The inspectors reviewed procedural changes to assess the adequacy of access controls for high and very high radiation areas to determine whether procedural changes substantially reduced the effectiveness and level of worker protection.

The inspectors assessed the controls of high radiation areas greater than 1 rem/hour and areas with the potential to become high radiation areas greater than 1 rem/hour for compliance with Technical Specifications and procedures.

The inspectors assessed the controls for very high radiation areas and areas with the potential to become very high radiation areas. The inspectors also assessed whether individuals were unable to gain unauthorized access to these areas.

These inspection activities constituted one sample as defined in IP 71124.01–05.

b. Findings

No findings were identified.

.6 Radiation Worker Performance and Radiation Protection Technician Proficiency (02.07)

a. Inspection Scope

The inspectors observed radiation worker performance and assessed their performance with respect to radiation protection work requirements, the level of radiological hazards present, and radiation work permit controls.

The inspectors assessed worker awareness of electronic alarming dosimeter set points, stay times, or permissible dose for radiologically significant work as well as expected response to alarms.

The inspectors observed radiation protection technician performance and assessed whether the technicians were aware of the radiological conditions and radiation work permit controls and whether their performance was consistent with training and qualifications for the given radiological hazards.

The inspectors observed radiation protection technician performance of radiation surveys and assessed the appropriateness of the instruments being used, including calibration and source checks.

These inspection activities constituted one sample as defined in IP 71124.01–05.

b. Findings

No findings were identified.

.7 Problem Identification and Resolution (02.08)

a. Inspection Scope

The inspectors assessed whether problems associated with radiological hazard assessment and exposure controls were being identified at an appropriate threshold and were properly addressed for resolution. For select problems, the inspectors assessed the appropriateness of the corrective actions. The inspectors also assessed the licensee's program for reviewing and incorporating operating experience.

The inspectors reviewed select problems related to human performance errors and assessed whether there was a similar cause and whether corrective actions taken resolve the problems.

The inspectors reviewed select problems related to radiation protection technician error and assessed whether there was a similar cause and whether corrective actions taken resolve the problems.

These inspection activities constituted one sample as defined in IP 71124.01–05.

b. Findings

No findings were identified.

2RS2 Occupational As-Low-As-Reasonably-Achievable Planning and Controls (71124.02)

.1 Verification of Dose Estimates and Exposure Tracking Systems (02.03)

a. Inspection Scope

The inspectors assessed whether the assumptions and basis for the current annual collective exposure estimate were reasonably accurate. The inspectors assessed source term reduction effectiveness and reviewed applicable procedures for estimating exposures from specific work activities.

The inspectors determined whether a dose threshold criteria was established to prompt additional reviews and/or additional as-low-as-reasonably-achievable (ALARA) planning and controls and evaluated the licensee's method of adjusting exposure estimates, or re-planning work, when unexpected changes in scope or emergent work were encountered. The inspectors determined if adjustments to exposure estimates were based on sound radiation protection and ALARA principles or if they are just adjusted to account for failures to control the work. The inspectors evaluated whether there was sufficient station management review and approval of adjustments to exposure estimates and that the reasons for the adjustments were justifiable.

These inspection activities supplemented those documented in Inspection Report 05000373/2016004; 05000374/2016004 and constituted one complete sample as defined in IP 71124.02–05.

b. Findings

No findings were identified.

.2 Problem Identification and Resolution (02.06)

a. Inspection Scope

The inspectors reviewed self-assessments and/or audits performed of the ALARA program and determined if these reviews identified problems or areas for improvement.

The inspectors assessed whether problems associated with ALARA planning and controls were being identified by the licensee at an appropriate threshold and properly addressed for resolution.

These inspection activities constituted one complete sample as defined in IP 71124.02–05.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness, Public Radiation Safety, Occupational Radiation Safety, and Security

4OA1 Performance Indicator Verification (71151)

.1 Unplanned Scrams per 7000 Critical Hours

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Scrams per 7000 Critical Hours performance indicator (PI) for Units 1 and 2 from the first quarter 2016 through the fourth quarter 2016. To determine the accuracy of the PI data reported, PI definitions and guidance contained in the Nuclear Energy Institute (NEI) Document 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 31, 2013, were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, event reports and U.S. Nuclear Regulatory Commission (NRC) Integrated Inspection Reports for the first quarter 2016 through the fourth quarter 2016 to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two unplanned scrams per 7000 critical hours samples as defined in IP 71151–05.

b. Findings

No findings were identified.

.2 Unplanned Scrams with Complications

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Scrams with Complications PI for Units 1 and 2 from the first quarter 2016 through the fourth quarter of 2016. To determine the accuracy of the PI data reported, PI definitions and guidance contained in NEI 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 31, 2013, were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, event reports and NRC Integrated Inspection Reports for the first quarter 2016 through the fourth quarter 2016 to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two unplanned scrams with complications samples as defined in IP 71151–05.

b. Findings

No findings were identified.

.3 Unplanned Power Changes per 7000 Critical Hours

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Transients per 7000 Critical Hours PI for Units 1 and 2 from the first quarter of 2016 through the fourth quarter of 2016. To determine the accuracy of the PI data reported, PI definitions and guidance contained in NEI 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 31, 2013, were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, maintenance rule records, event reports and NRC Integrated Inspection Reports for the first quarter 2016 through the fourth quarter 2016 to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two unplanned transients per 7000 critical hours samples as defined in IP 71151–05.

b. Findings

No findings were identified.

.4 Drill/Exercise Performance

a. Inspection Scope

The inspectors sampled licensee submittals for the Drill/Exercise PI for the period from the third quarter of 2016 through the fourth quarter of 2016. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 31, 2013, were used. The inspectors reviewed the licensee's records associated with the PI to verify that the licensee accurately reported the Drill/Exercise PI in accordance with relevant procedures and the NEI guidance. Specifically, the inspectors reviewed licensee records, and processes including procedural guidance on assessing opportunities for the PI; assessments of PI opportunities during pre-designated control room simulator training sessions; performance during the 2016 biennial exercise; and performance during other drills. Documents reviewed are listed in the Attachment to this report.

This inspection constitutes one Drill/Exercise PI sample as defined in IP 71151.

b. Findings

No findings were identified.

.5 Emergency Response Organization Drill Participation

a. Inspection Scope

The inspectors sampled licensee submittals for the Emergency Response Organization (ERO) Drill Participation PI for the period from the third quarter 2016 through the fourth quarter 2016. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 31, 2013, were used. The inspectors reviewed the licensee's records associated with the PI to verify that the licensee accurately reported the indicator in accordance with relevant procedures, and NEI guidance. Specifically, the inspectors reviewed licensee records and processes, including procedural guidance on assessing opportunities for the PI; performance during the 2016 biennial exercise; and other drills; and revisions of the roster of personnel assigned to key ERO positions. Documents reviewed are listed in the Attachment to this report.

This inspection constitutes one ERO drill participation sample as defined in IP 71151.

b. Findings

No findings were identified.

.6 Alert and Notification System

a. Inspection Scope

The inspectors sampled licensee submittals for the Alert and Notification System (ANS) PI for the period from the third quarter of 2016 through the fourth quarter of 2016. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 31, 2013, were used. The inspectors reviewed the licensee's records associated with the PI to verify that the licensee accurately reported the indicator in accordance with relevant procedures and the NEI Guidance. Specifically, the inspectors reviewed licensee records and processes including procedural guidance on assessing opportunities for the PI and results of periodic ANS operability tests. Documents reviewed are listed in the Attachment to this report.

This inspection constitutes one ANS sample as defined in IP 71151.

b. Findings

No findings were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Items Entered into the Corrective Action Program

a. Inspection Scope

As discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify they were being entered into the licensee's corrective action program (CAP) at an appropriate threshold, adequate attention was being given to timely corrective actions, and adverse trends were identified and addressed. Some minor issues were entered into the licensee's CAP as a result of the inspectors' observations; however, they are not discussed in this report.

These routine reviews for the identification and resolution of problems did not constitute any additional inspection samples. Instead, by procedure they were considered an integral part of the inspections performed during the quarter.

b. Findings

No findings were identified.

.2 Daily Corrective Action Program Reviews

a. Inspection Scope

To assist with the identification of repetitive equipment failures and specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee's CAP. This review was accomplished through inspection of the station's daily condition report packages.

These daily reviews were performed by procedure as part of the inspectors' daily plant status monitoring activities and, as such, did not constitute any separate inspection samples.

b. Findings

No findings were identified.

4OA3 Follow-Up of Events and Notices of Enforcement Discretion (71153)

.1 Unit 2 Manual Reactor Scram on Main Generator Runback (L2F45)

a. Inspection Scope

The inspectors reviewed the plant's response to a Unit 2 manual reactor trip on January 23, 2017, at 8:08 a.m. after the unit experienced a transient at 8:05 a.m. with the stator water cooling system that caused a main generator runback. A manual scram was inserted as required by LOA–GC–201. All control rods fully inserted as expected and all major equipment functioned as designed.

Stator water cooling flow was subsequently restored and the unit restarted on January 25, with full-achievable power being reached on January 28. The inspectors responded to the control room and performed in-field observations following this event and reviewed available documentation related to the event and the associated corrective actions. Documents reviewed are listed in the Attachment to this report.

This event follow-up review constituted one sample as defined in IP 71153–05.

b. Findings

No findings were identified.

.2 Unit 1 Automatic Reactor Scram on Generator Differential Current (L1F44)

a. Inspection Scope

The inspectors reviewed the plant's response to a Unit 1 automatic reactor trip on February 13, 2017. The station was attempting to back-feed the Unit 2 unit auxiliary transformer from the grid when an unexpected failure occurred with the main generator output bus ducts, leading to a generator trip. This resulted in the turbine control valves' fast closure, a turbine trip, and the Unit 1 automatic scram at 11:09 p.m. The damaged components were repaired and the unit was restarted on February 17.

The inspectors responded to the control room, performed in-field observations following this event and reviewed available documentation related to the event and the associated corrective actions. Documents reviewed are listed in the Attachment to this report.

This event follow-up review constituted one sample as defined in IP 71153–05.

b. Findings

No findings were identified.

.3 Unit 1 Manual Reactor Scram on Motor Driven Reactor Feed Pump Regulating Valve Failure (L1F45)

a. Inspection Scope

The inspectors reviewed the plant's response to a Unit 1 reactor trip on February 17, 2017. The trip occurred after the motor driven reactor feed pump feed regulating valve failed full open due to the 1FW005 valve positioner feedback arm breaking into two pieces. With the positioner feedback arm severed, the valve rapidly failed to the full open position, resulting in a rapid increase in reactor water level. Operations personnel manually scrammed the reactor in response to the valve failure and rapid increase in reactor water level. Unit 1 was restarted and synchronized to the grid on February 19.

The inspectors responded to the control room, performed in-field observations following this event and reviewed available documentation related to the event and the associated corrective actions. Documents reviewed are listed in the Attachment to this report.

This event follow-up review constituted one sample as defined in IP 71153–05.

b. Findings

No findings were identified.

4OA5 Other Activities

.1 (Closed) NRC Temporary Instruction 2515/192, "Inspection of the Licensee's Interim Compensatory Measures Associated with the Open Phase Condition Design Vulnerabilities in Electric Power Systems"

a. Inspection Scope

The objective of this performance based Temporary Instruction (TI) is to verify implementation of interim compensatory measures associated with an open phase condition (OPC) design vulnerability in electric power system for operating reactors. The inspectors conducted an inspection to determine if the licensee had implemented the following interim compensatory measures. These compensatory measures are to remain in place until permanent automatic detection and protection schemes are installed and declared operable for OPC design vulnerability. The inspectors verified the following:

- The licensee had identified and discussed with plant staff the lessons-learned from the OPC events at the U.S. operating plants including the Byron station OPC event and its consequences. This includes conducting operator training for promptly diagnosing, recognizing consequences, and responding to an OPC event.

- The licensee had updated plant operating procedures to help operators promptly diagnose and respond to OPC events on off-site power sources credited for safe shutdown of the plant.

- The licensee had established and continue to implement periodic walkdown activities to inspect switchyard equipment such as insulators, disconnect switches, and transmission line and transformer connections associated with the offsite power circuits to detect a visible OPC.

- The licensee had ensured that routine maintenance and testing activities on switchyard components have been implemented and maintained. As part of the maintenance and testing activities, the licensee assessed and managed plant risk in accordance with 10 CFR 50.65(a) (4) requirements.

b. Findings and Observations

No findings of significance were identified. The inspectors verified the criteria were met.

4OA6 Management Meetings

.1 Exit Meeting Summary

On April 5, 2017, the inspectors presented the inspection results to Mr. H. Vinyard, Plant Manager, and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors confirmed that none of the potential report input discussed was considered proprietary.

.2 Interim Exit Meetings

Interim exits were conducted for:

- the results of the emergency preparedness program inspection were discussed with Mr. W. Trafton, on March 30, 2017;
- the inspection results for the inservice inspection with Mr. W. Trafton and other members of the licensee's staff on February 16, 2017; and
- the inspection results for the radiation safety program review with Mr. W. Trafton, Site Vice President, on February 17, 2017.

The inspectors confirmed that none of the potential report input discussed was considered proprietary. Proprietary material received during the inspection was returned to the licensee.

4OA7 Licensee-Identified Violations

The following violation of very low significance (Green) was identified by the licensee and is a violation of NRC requirements which meets the criteria of the NRC Enforcement Policy for being dispositioned as a Non-Cited Violation (NCV).

- Title 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and drawings," requires, in part, that activities affecting quality 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, or drawings. Contrary to this, on February 6, 2017, the licensee failed to accomplish an activity affecting quality in accordance with licensee procedure, CC–AA–201, Revision 11, "Plant Barrier Control Program." Specifically, the licensee failed to implement compensatory actions required by the Plant Barrier Control Program which resulted in multiple doors being impaired at the same time such that safety-related equipment in the Unit 2 Division II switchgear room and Unit 2 749' Auxiliary Building were declared inoperable. The licensee documented the issue in their CAP as Action Request (AR) 3972830.

  The inspectors determined that this issue was of very low safety significance because the finding: (1) was not a deficiency affecting the design or qualification of a mitigating structure, system, or component (SSC); (2) did not represent a loss of system and/or function; (3) did not represent the actual loss of safety function of at least a single train for greater than its technical specification (TS) allowed outage time; (4) did not represent an actual loss of one or more non–TS trains of equipment during shutdown designated as risk significant for greater than 24 hours; and (5) did not degrade a functional auto-isolation of residual heat removal (RHR).

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

W. Trafton, Site Vice President
H. Vinyard, Plant Manager
J. Kowalski, Engineering Director
G. Ford, Regulatory Assurance Manager
J. Moser, Radiation Protection Manager
A. Schierer, Programs Engineering Manager
M. Hayworth, Emergency Preparedness Manager
R. Conley, Operation Manager
D. Murray, Regulatory Assurance
T. Lanc, Principal Regulatory Engineer
M. McDonald, Corporate Senior Staff Engineer
R. Stubblefield, Site Structural Engineer
L. Simpson, Corporate Senior Engineering Manager
J. Miller, Corporate NDES Level III
G. Brumbelow, Emergency Preparedness Coordinator
S. Tanton, Design Engineering Manager
R. Conley, Radiation Engineering Manager
D. Wright, Operations Training Manager
D. Anthony, Exelon NDES Manager West
B. Casey, Inservice Inspection Programs Engineering
D. Mivens, Radiation Protection Technician

U.S. Nuclear Regulatory Commission

K. Stoedter, Chief, Reactor Projects Branch 1

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000373/2017001–01; 05000374/2017001–01	NCV	Inadequate Controls for ASME Code VT–3 Internal Examination of Pumps and Valves (Section R08.5.b)
05000373/2017001–02	NCV	Failure to Perform Preventive Maintenance Resulted in Stem-to-Disc Separation of Safety-Related Valve (Section 1R15)

Closed

05000373/2017001–01; 05000374/2017001–01	NCV	Inadequate Controls for ASME Code VT–3 Internal Examination of Pumps and Valves (Section R08.5.b)
05000373/2017001–02	NCV	Failure to Perform Preventive Maintenance Resulted in Stem-to-Disc Separation of Safety-Related Valve (Section 1R15)
2515/192	TI	Inspection of the Licensee's Interim Compensatory Measures Associated with the Open Phase Condition Design Vulnerabilities in Electric Power Systems (Section 4OA5)

LIST OF DOCUMENTS REVIEWED

The following is a partial list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspector reviewed the documents in their entirety, but rather that selected sections or 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.

1R04 Equipment Alignment

- AR 3970662; Unable to Open 2E12–F009 During Shutdown Cooling Startup
- AR 3971081; TCCP Needed for Lead Left Lifted After Troubleshooting
- AR 3971081; TCCP Needed for Lead Left Lifted After troubleshooting
- AR 3975925; Unable to Flush 2B RHR Pump Disch Pipe to Acceptable Limits
- AR 3976698; 2E12–F436B Unable to Be Fully Opened/Closed
- AR 3976825; 2E12–F050A Failed LLRT
- AR 3978544; Discharge Pressure for B&C RHR Water Leg Pump is Low
- AR 3978655; Line 2RHH1A–2” For 2E12–F403/404 is Clogged
- AR 3978920; Sheared Off Stud on 2” Flange Connection
- AR 3979156; 2A RHR Discharge Check Leaked By During Spool Work
- AR 3979418; NDE UT Thickness Reading Below TMin. On 2RH90B–6
- AR 3980080; 2B RHR Low Pressure Alarm Will Not Clear
- AR 3980612; Valve Leaks By When Closed
- CR 3970662; CAP Evaluation—Unable to Open 2E12–F009 During Shutdown Cooling Startup; 3/15/2017
- LOP–LV–02M; Unit 2 Locked Valve Position Checklist; 11/17/2016
- LOP–RH–2BM; Unit 2 B Residual Heat Removal System Mechanical Checklist; 2/17/2016
- M-142; P&ID Residual Heat Removal System (RHRS); Revision AZ
- M–147; P&ID Reactor Core Isolation Coolant System (R.C.I.C.); Revision AD
- WO 943883–02; Root Cause Investigation, Determine Cause for the Loss of Shut Down Cooling with U1 in Mode 4, Cold Shutdown; 7/20/2009

1R05 Fire Protection

- AR 3979640; NRC Question, Transient Combustibles
- FZ 7B2; LaSalle Pre-Fire Plan Layout, Unit 1 Elevation 710’–0” Division 1 Standby Diesel Generator Room; Revision 2
- FZ 7C3; LaSalle Pre-Fire Plan Layout, Unit 1 Elevation 674’–0” Division 1 Diesel Fuel Tank Room; Revision 1
- FZ 7C6; LaSalle Pre-Fire Plan Layout, Unit 1 Elevation 674’–0” Division 1 RHR Service Water Pump Room; Revision 1
- L–000776; LaSalle County Station Combustible Load Calculation; Revision 8
- OP–AA–201–009; LaSalle—Site Specific Information, Aid to Determine if a Transient Combustible Permit is Required for Transient Combustible Materials; Revision 18
- OP–AA–201–009; LaSalle—Site Specific Information, Critical Buildings List; Revision 18

1R08 Inservice Inspection Activities

- AR 2446297; 2B33–F067A Failed to Close; 2/2/2015
- AR 2478819; Issues Noted During L2R15 for Reactor Recirculation Loop Discharge Isolation Valves 2B33–F067A and 2B33–F067B
- AR 2545426; Core Plate Bolt Inspection Deviation; 8/23/2015

- AR 2629627; 1E21-C001 Wear on Pump Centering Ring; 2/22/2016
- AR 2632117; FME "A" SRM Dry Tube Spring in RPV; 2/25/2016
- AR 2690080; Plugged Quills on U2 WS; 7/4/2016
- AR 2708986; Degradation on 2WS087B; 8/26/2016
- AR 2724251; D RHR Discharge Valve Erosion; 10/5/2016
- AR 3971819; NRC Identified Documentation Issue; 2/7/2017
- AR 3972620; L2R14 Timing of 2B33–F067B VT–3 Examination; 2/2/2017
- ASME Section XI Repair Replacement Plan; 2/11/2015
- ASME Weld Data Record- Welds 1A, 1B, 1C, 1D on Valve 2B33–F067A; 2/12/2015
- ASME Welder Performance Qualification- Welder CH1989; 9/25/2013
- Drawing F-22587a; 24” 908# Wedge Type Gate Valve; Revision 5
- EPRI PDQS No. 1222; PDI-UT-1, Revision E, Addenda 0; Date of Issue 9/10/2015
- EPRI PDQS No. 1223; PDI-UT-1, Revision E, Addenda 0; Date of Issue 9/11/2015ER-AA-335-017; Visual Examination of Pump and Valve Internals, Revision 8
- EPRI PDQS No. 157; PDI-UT-1, Revision A, Addenda 0; Date of Issue 2/13/2013
- EPRI PDQS; GEH-UT-247; 9/14/2003
- EPRI PDQS; GEH-UT-716; 5/9/2008
- EPRI PDQS; PDI-UT-1; 7/20/2016
- ER-AA-335-003; Magnetic Particle Examination; Revision 7
- ER-AA-335-010; Guidelines for ASME Code Allowable Flaw Evaluation and ASME Code Coverage Calculations; Revision 5
- ER-AA-335-1008; Code Acceptance & Recording Criteria for Nondestructive (NDE) Surface Examination; Revision 4
- GEH-PDI-UT-1; PDI Generic Procedure for the Ultrasonic Examination of Ferritic Pipe Welds; Version 10
- GEH-UT-247; Procedure for Phased Array Ultrasonic Examination of Dissimilar Metal Welds; Version 3
- GEH-UT-716; Procedure for the Examination of Reactor Pressure Vessel Welds Form the Outside Surface with MicroTomo in Accordance with Appendix VIII, Version 3
- Report 13-606; VT–3 Visual Examination-Internal Surface Valve 2B33–F067B; 2/25/2013
- Report 15-524; Liquid Penetrant Examination Data Sheet- Welds 1A, 1B, 1C, 1D on Valve 2B33–F067A; 2/17/2015
- Report L2R15-APR-005; Ultrasonic Examination Summary Sheet ILP-2001-26A; 2/19/2015
- Report L2R16-MT-001; Magnetic Particle Examination of weld GEL-1060-AG; Exam Date 2/10/2017
- Report L2R16-UT-003; UT Calibration/Examination of Weld IMS-2036-07; Exam Date 2/8/2017
- Report L2R16-UT-004; UT Calibration/Examination of Weld IMS-2001-08; Exam Date 2/9/2017
- Report L2R16-UT-005; UT Calibration/Examination of Weld IMS-2003-13; Exam Date 2/9/2017
- Report L2R16-UT-006; UT Calibration/Examination of Weld IMS-2001-20; Exam Date 2/9/2017
- Report L2R16-UT-007; UT Calibration/Examination of Weld IMS-2002-16; Exam Date 2/9/2017
- Report L2R16-UT-008; UT Calibration/Examination of Weld IMS-2004-07; Exam Date 2/9/2017
- WO 1614962; 2B33–F067B Indicated Dual Upon Valve Closure; 2/26/2013
- WPS 8-8-GT-2; Revision 1

1R13 Maintenance Risk Assessments and Emergent Work Control

- ACPS 17–019; Abnormal Component Position, IR 3972858; 2/11/2017
- AR 3947786; 2B DG Strainer Backwash Valve 2E22–F319 MOV Not Working
- AR 3968369; 2B DG Cooling Water STNR BW Valve Not Operating Correctly
- AR 3972858; Event Report: Skimmer Surge Tank Reject Valve Stuck Open; 2/11/2017
- AR 3972858; Fuel Pool Cooling Reject Valve Stuck Open
- AR 3973140; 4.0 Critique for 2FC017 Failing Open
- AR 3973603; U2 250 Battery Charger HV Alarm Card OOT
- AR 3973609; U2 250V Battery Charger LV Alarm Card OOT
- EC 617477; Alternate Decay Heat Removal (ADHR) System Qual for L2R16 Outage; Revision 000
- LAP–100–56; Equipment/Parts Storage in Plant Areas Containing Safety-Related Equipment; Revision 9
- LAS–2–2017–0048; Risk Assessment ODM: Unit 2 GC, (AR 3965520); 1/2017
- LAS–2–2017–0052; L2F4S Entering Mode 2 w/o GC (AR 3965520); Revision 0
- LOA–FC–201; Unit 2 Fuel Pool Cooling System/Reactor Cavity Level Abnormal; Revision 26
- LOP–FC–03; Fuel Pool Cooling System Startup, Operation, Shutdown, Level Changes, and Flushing; Revision 54
- LOR–2H13–P601–C207/1E–2–4032AK; Fuel Pool Cooling System Trouble; Revisions 3 & 4; 2/12/2017
- OP–AA–106–101–1006; Operational Decision Making Process; Revision 17
- OP–AA–108–108; Engineering Department Start-Up Checklist, 1/24/2017
- Operations Log; 2/11/2017
- OP–LA–101–111–1002; Risk Recognition/Decision Making Process Flowchart; Revision 69

1R15 Operability Determinations and Functional Assessments

- 1922952–01; LOS–DG–M3 2B DG Fast Start ATT 2B-Fast; 12/1/2016
- 3968369; 2B DG Cooling Water STNR BW Valve Not Operating Correctly
- AR 122320; Evaluate CSCS Service Wtr Components for Corrosion/Erosion
- AR 3972830; Compensatory Measures for PBI’s Not Met
- AR 3972830; Compensatory measures for PBI’s Not Met
- AR 3972901; 2E22–F004 Valve Appears to be Stem/Disc Separated
- AR 3972910; Valve Stem Appears to Have Separated From the Disc
- AR 708358; PI&R Inspection — Untimely CAS for CSCS Valve Replacements
- CC–AA–201; Plant Barrier Control Program; Revision 11
- CR 3968369; 2B DG Cooling Water Strainer Backwash Valve 2E22–F319 Not Operating Correctly; 3/10/2017
- EC 389155–000; Engineering Change: Consequence of Failure to Properly Implement PBI Compensatory Actions Regarding Doors to Unit 1 TDRFP Rooms; 6/6/2012
- EC 392469; Pre-Installation Review – Stainless Steel Valves; Revision 000
- EC 397707; As Build for Valve 2E22–F319; Revision 000
- FAI/12–0246; Calculation from Fauske & Associates, LLC, LaSalle Unit 1 Evaluation of TDRFP Access Plug Removal with Loss of Room Integrity During a Postulated Unit 2 HELB Event; 5/29/2012
- IT–7000–M–PP–16; Generic CSCS Valves Replacement Details; Revision W
- Operator’s Log Entries; 2/6/2017
- PMCR 00084595; U 1(2) / 12 inch Gate Valve 1 (2) E22–F319; 2014
- PMCR 00090111; U-1 00063065-02/ U-2 00069931-02, 1(2) B DG DW Strainer Backwash Valve; 2015

- RCR 122320; Root Cause Report – CSCS Valve Failures; 12/12/2002
- RCR AR 122320-02; Root Cause Report – Determine Technical Reason for CSCS Valve Failures; 9/3/2002
- RCR NTS 00153.00; Root Cause Report 0DG009 Diesel Generator Service Water Strainer Backwash Valve Stem/Disc Separation; 9/6/1996
- SR TIPMA11; Service Request, Predefine Change CSCS Valve PM Changes; 2/6/2017
- TIMD031; Additional Details Screenshot of Unit 2 DG Building MOVA F319; Undated
- WC–AA–120; Preventive Maintenance (PM) Database Revision Requirements; Revision 2
- WO 1724689–01; Need T-Gap Measurement on 2E22–F319; 4/14/2017
- WO 1740294–09; Plant Barrier Impairment Permit, PBI DR–255.01r11; 2/6/2017
- WO 1807386–03; Plant barrier Impairment Permit; DR–284.00r10; Prop Door Open; 2/13/2015
- WO 1807386–04; Plant Barrier Impairment Permit, DR–284.00r11, Prop Door Open; 2/7/2017
- WO 1814789–02; Plant barrier Impairment Permit, DR–269.01R11; Prop Door Open; 3/16/2016
- WO 1949667–01; LOS–DG–Q3, 2B D/G Cooling Water Pump Inserv Test, Att B5; 11/30/2016
- WO 4572806–01; LRA LOS–DG–M3 2B DG Idle Start ATT 2B-Idle; 12/29/2016
- WO 960085699–01; DG 2B Cooling WTR Strainer Backwash OTLT; 9/16/1996
- WO 960085699–02; Actuator, HPCS Diesel Cool WTR Strainer; 9/22/1996
- WO 960085699–03; Actuator, HPCS Diesel Cool WTR Strainer; 9/20/1996

1R18 Plant Modifications

- EC 406915; L2R16 Decay Heat and Related Computations; Revision 0

1R19 Post-Maintenance Testing

- AR 2718749; Erratic Voltage Indication at 4400 Volts
- AR 3943741; Erratic Voltage and Frequency Indication while Raising Voltage
- AR 3965520; Complex Troubleshooting Plan for Generator Cooling System Failure; 1/2017
- AR 3969409; LOS–DG–SR7 New Value Values for 2E22–F319
- AR 3969415; 2E22–F319 — MOV Setpoint Binder Revision
- AR 3976927; 2B RHR Pump Discharge Check Valve Leak by
- AR 3980080; 2B RHR Low Pressure Alarm Will Not Clear
- LAS–2–2017–0048; Risk Assessment, ODM: Unit 2 GC; 1/2017
- LAS–2–2017–0052; Simple Issue Risk Assessment: L2F45 Entering Mode 2 w/o GC; 1/2017
- LOS–RH–Q1; Unit 2 B RHR System Operability and Inservice Test (Test Notes); 2/2017
- WO 4583278–01; LRA LOS–DG–M2 2A Diesel Generator ATT 2A-Idle; 1/20/2017
- WO 818621–11; 2E22–F319: Inspect/Replace/Refurb Valve

1R20 Refueling and Other Outage Activities

- AR 3975170; WHR Deviation Due to Individual Detained – Dose Rate Alarm
- AR 3975561; CB&I Fatigue Assessment
- AR 3975596; WHR Deviation Due to Offsite Medical – CB&I PF
- AR 3976050; WHR Deviation Due to Contamination – CB&I PF
- AR 3977784; Fatigue Assessment (*sic*) – Post Event
- AR 3977788; WHR Deviation Due to Individual Detained by RP – Dose Rate Alarm – CB&I PF
- L2R16 Refuel Outage Design Change Scope; Undated
- L2R16 Shutdown Safety Plan; 1/23/2017
- LS–AA–119; Fatigue Management and Work Hour Limits; Revision 12
- Manpower Schedule Plan for Various Individual Workers; 2/5 – 2/26/2017

- NF–LA–715; Critical Prediction Checklist, Unit 2, Cycle 17; 3/8/2017; Revision 1
- NF–LA–721; Control Rod Move Sheet, U2, Sequence ID SAr1.0; 2/2017
- Work Schedule Report for EMD; 2/2017 – 3/2017
- Work Schedule Report for IMD; 2/2017 – 3/2017
- Work Schedule Report for MMD; 2/2017 – 3/2017
- Work Schedule Report for Operations; 2/2017 – 3/2017

1R22 Surveillance Testing

- AR 3964435; DOS 6600–12 Not Revised per ACIT
- WO 1814723–01; U2 RCIC S/P Check Valve TST LOS–RI–R4, ATT 1A/LOS–RI–Q3, ATT; 3/9/2017
- AR 3983474; Unable to Adjust to Desired Reading During LOS–RI–Q3
- AR 3981500; Procedure Revision Needed to LOS–DG–209
- AR 398175; 2CM030 Erratic Valve Indication When Closed
- AR 3981406; Division 1 Post LOCA Monitor Reading Low on O2 Channel
- AR 3987206; PPC HPCS Pump Data Screen Discrepancy
- AR 2501498; TSSR 3.8.1.10: EDG Largest Load Reject
- WO1811310–01; Integrated Division I ECCS Response Time; 3/5/2017
- LOS–HP–Q1; Tech Spec Surveillance, HPCS Pump Run; 3/20/2017
- WO 4571748–01; LOS–CS–Q1 Sec Cont VR Dampers Att 1A; 3/22/2017
- WO 1811309–02; “0” DG Start and Load Acceptance Unit 2 A; 2/28/2017

1EP2 Alert and Notification Evaluation

- AR 02699153; EP Siren Failures (LS09/LS19); 8/1/2016
- AR 02704537; EP Siren Failure (LS04); 8/15/2016
- AR 02712616; EP Siren Failure (LS07); 9/9/2016
- AR 02723490; EP–Update the MW Siren Design Reports; 10/3/2016
- AR 02724917; EP-1st Half 2016 MW ANS Siren Trend; 10/6/2016
- AR 02728150; EP Siren Failure (LS12); 10/14/2016
- AR 02735578; EP Siren Failure (LS12); 11/1/2016
- AR 03986300; EP-2nd Half 2016 MW Siren Trend Report; 3/17/2017
- AR 03991549; NRC Observation: ANS Design Report Needs Updating; 3/30/2017
- Emergency Planning for the LaSalle Area – Important Safety Information for Your Community; 2016/2017
- EP-AA-1000; Exelon Nuclear Standardized Radiological Emergency Plan Section E; Revision 28
- EP-AA-1005; Exelon Nuclear Radiological Emergency Plan Annex for LaSalle Station, Section 4; Revision 39
- EP-AA-114; Notifications; Revision 13
- LaSalle Monthly Siren Availability Reports; 3/1/2015, through 3/31/2017
- Offsite Emergency Plan Prompt Alert and Notification System Addendum for the LaSalle Nuclear Power Station; May 2013
- Semi-Annual LaSalle Siren Reports; 1/1/2016, through 12/31/2016
- Siren Daily Operability Reports; 3/1/2015, through 3/31/2017

1EP3 Emergency Response Organization Augmentation Testing

- Activation and Operation; Revision 18
- AR 2487614; Greater Than 60 Minute Response to the Call-In Drill; 3/26/2015

- AR 2522766; Training – Aggregate Review of Cycle 15-3 EP Performance; 6/29/2015
- AR 2683747; LAS-EP-2016-PEX-SIM Failed Objective; 6/15/2016
- AR 2685112; ERO Duty Phone Did Not Receive OCC Staffing Call; 6/23/2016
- EP-AA-1000; Exelon Nuclear Standardized Radiological Emergency Plan, Sections B, N and O; Revision 28
- EP-AA-1005, Addendum 1; LaSalle Station On-Shift Staffing Technical Basis; Revision 1
- EP-AA-1005; Exelon Nuclear Radiological Emergency Plan Annex for LaSalle Station; Revision 38
- EP-AA-112; Emergency Response Organization (ERO)/Emergency Response Facility (ERF)
- EP-AA-112-100-F-06; ERO Notification or Augmentation; Revision V
- EP-AA-113; Personnel Protective Actions; Revision 11
- EP-AA-120; Emergency Plan Administration; Revision 16
- EP-AA-122-100-F-13; Call-In Drill (CID) Checklist; Revision D
- ERO Training Records – Initial and Requalification Training (15 ERO Personnel)
- LaSalle Station Emergency Response Organization Duty Team Rosters; March 2017
- Quarterly Unannounced Off-Hours Call-In Augmentation Drill Results; March 2015 – January 2017
- Respirator SCBA Qualifications Status (Department) Records; January 2016 – March 2017
- TQ-AA-113; ERO Training and Qualification; Revision 23

<u>1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies</u>

- EP-AA-120-1006; EP Reportability-Loss of Emergency Preparedness Capabilities; Revision 3
- EP-AA-125; Emergency Preparedness Self Evaluation Process; Revision 10
- EP-AA-1005, Addendum 3; Emergency Action Levels for LaSalle Station; Revision 2
- EP-AA-1005, Addendum 2; Evacuation Time Estimates for LaSalle County Generating Station Plume Exposure Pathway Emergency Plan; Revision 1
- LaSalle County Generating Station 2015 Population Update Analysis; 11/18/2015
- LaSalle County Generating Station 2016 Population Update Analysis; 9/10/2016
- NOSA-LSA-15-03; LaSalle Station Emergency Preparedness Audit Report; 4/22/2015
- NOSA-NCS-16-03; LaSalle Station Emergency Preparedness Audit Report; 4/17/2016
- LaSalle EP Information Newsletter; December 2016, January 2017 and April 2017
- Corporate Letters of Agreement (Table); 12/31/2016
- Morris Hospital Letter of Agreement; 12/8/2016
- LaSalle County Sheriff Letter of Agreement; 12/8/2016
- Seneca Fire Department Letter of Agreement; 12/8/2016
- Seneca Ambulance Service Letter of Agreement; 12/8/2016
- Marseilles Fire Department Letter of Agreement; 12/8/2016
- Marseilles Area Ambulance Service Letter of Agreement; 12/8/2016
- AR 2628533; Focused Area Self-Assessment – 2017 NRC EP Routine/Program, PI Verification Inspection; 1/11/2017
- LaSalle 2015 Off-Year Exercise Evaluation Report; 10/13/2016
- LaSalle 2016 NRC Graded Exercise Evaluation Report; 8/18/2016
- LaSalle County Nuclear Station Performance Indicator Drill Evaluation Reports; 12/10/2015

- LaSalle 2016 First Biannual Health Physics Drill Findings and Observations Report; 7/27/2016
- LaSalle 2016 Medical and Health Physics Drill Findings and Observations Report; 10/14/2016
- AR 2428836; EP Alternate Facilities Enhancements; 12/22/2014
- AR 2508895; EP – Drill Objective Failures – LORT/EP PI Drill – Team A; 6/1/2015
- AR 2508937; One Month Decline in EP Departmental Performance Indicators; 6/2/2015
- AR 2522766; Training – Aggregate Review of Cycle 15-3 EP Performance; 6/29/2015
- AR 2537501; NOS ID: Station Management Support of EP Program; 8/4/2015
- AR 2592347; 2015 TSC Drill and Exercise Performance (DEP) Failures; 11/25/2015
- AR 2592347; AS–EP–2016–PEX–SIM Failed Objective 6/15/2016
- AR 2687339; Gap to Excellence in Emergency Preparedness; 6/29/2016
- AR 3962116; Loss of Required Environmental Monitoring Data; 1/12/2017
- AR 2701151; EAL Threshold Numeric Value Incorrect; 8/3/2016
- AR 2718973; EP – Discrepancies Identified in EP-AA-1005, Addendum 3; 8/3/2016
- AR 2735488; 3Q16 Drill Set Lessons Learned – September and October; 10/12/2016

2RS1 Radiological Hazard Assessment and Exposure Controls

- Active Source Inventory; 8/8/2016
- AP–AA–825–1014; Operation and Inspection of the 3M Versaflo TR–300 PAPR System; Revision 3
- AR 3973656; Two Suppression Pool Workers Contaminated; 2/13/2017
- Bi-Annual Source Inventory; 1/31/2017
- Bi-Annual Source Leak Test; 12/9/2016
- Radiation Work Permit and Associated ALARA File; LA–02–17–00512; L2R16 Drywell Control Rod Drive Activities; Multiple Dates
- Radiation Work Permit and Associated ALARA File; LA–02–17–00548; L2R16 DW 2B33–F067A Repairs/Inspections; Multiple Dates
- Radiation Work Permit and Associated ALARA File; LA–02–17–00549; DW 2B33–F067B Inspections and Repair Activities; Multiple Dates
- Radiation Work Permit and Associated ALARA File; LA–02–17–00701; L2R16 Suppression Pool Diving Activities; Multiple Dates
- Radiation Work Permit and Associated ALARA File; LA–02–17–00702; L2R16 Suppression Pool Radiation Protection Activities; Multiple Dates
- Radiation Work Permit and Associated ALARA File; LA–02–17–00703; L2R16 Suppression Pool Work Activities; Multiple Dates
- RP–AA–301; Radiological Air Sampling Program; Revision 10
- RP–AA–350; Personnel Contamination Monitoring, Decontamination and Reporting; Revision 18
- RP–AA–401–1002; Radiological Risk Management; Revision 10
- RP–AA–403; Administration of the Radiation Work Permit System; Revision 9
- RP–AA–440; Respiratory Protection Program; Revision 13
- RP–AA–461; Radiological Controls for Contaminated Water Diving Operations; Revision 7
- RP–AB–460–1003; Radiation Protection Post SCRAM Response; Revision 1

2RS2 Occupational ALARA Planning and Controls

- RP–AA–400; ALARA Program; Revision 13
- RP–AA–401; Operational ALARA Planning and Controls; Revision 021

4OA1 Performance Indicator Verification

- EP-AA-125-1001; Performance Indicator Guidance; Revision 9
- LaSalle 1 Performance Indicators; 3Q/2016
- LaSalle 2 Performance Indicators; 3Q/2016
- LS-AA-2110; Monthly Data Elements for ERO Drill Participation; July 2016 - December 2016
- LS-AA-2120; Monthly Data Elements for NRC Drill/Exercise Performance; July 16 - December 2016
- LS-AA-2130; Monthly Data Elements for NRC ANS Reliability; July 2016 - December 2016
- Unit 1 Planned Power Changes Graph; 2016
- Unit 1 Unplanned Scrams per 7000 Critical Hours, 2015–2016
- Unit 2 Planned Power Changes Graph; 2016
- Unit 2 Unplanned Scrams per 7000 Critical Hours, 2015–2016

4OA2 Identification and Resolution of Problems

Action Requests Generated from NRC or IEMA INSPECTION

- 3961480; IEMA Identified Water on Floor from Roof Leak
- 3971819; NRC Identified Documentation Issue
- 3972620; NRC—L2R14 Timing of 2B33–F067B VT–3 Examination
- 3975085; NRC Identified: Hot Shop DAW
- 3975089; NRC Identified: Cavity Air Sampling
- 3976874; TRNG – Licensee Address Change
- 3979451; FOF Protective Strategy Template Updated from NRC Cycle IV
- 3979640; NRC Question: Transient Combustibles
- 3982661; NRC Identified—Closeout Inspection of U2 DW 807, 796, 777
- 3987848; NRC Feedback From Temporary Inspection 2515/192
- 3991549; NRC Observation: ANS Design Report Needs Updating
- 3995406; NRC Identified Discrepancy in ROP Initiating Event Performance Indicators
- 39990585; NRC Identified Prefer'd "As Left" Switch Position Not Correct

4OA3 Follow-Up of Events and Notices of Enforcement Discretion

- 58864 CD0; LaSalle Station Unit 2; Detailed Control Rod Information for Rods (Various) — Raw Data; 1/23/2017
- AR 3965514; 2A Heater String Isolated on High Level
- AR 3965520; Unit 2 Manually Scrammed Due to a GC Runback
- AR 3965520; Unit 2 Manually Scrammed Due to a GC Runback
- AR 3965554; OCB 3–4 Tripped Open on Pole Disagreement
- AR 3965578; HCU 02–43 Accumulator Had Lower Pressure After SCRAM Reset
- AR 3965626; 2B21–MOVSV1 Showing Dual Would Not Close
- AR 3973691; LPRM 08–25A Failed Upscale During Unit 1 Scram
- AR 3973722; E Group LPRM Fails Upscale During Scram
- AR 3973766; 1ES006C Did Not Isolate
- AR 3973781; Unit 1 A Heater String Isolation During Scram
- AR 3973783; 1C11–F389 Indicated Dual

- AR 3973812; Various Recorder Alarms Following Scram
- AR 3973989; 1B21–RSSV–1 Steam Leak
- AR 3974142; 1B21–F513A Tripped On Thermal Overloads
- AR 3974202; FRV Instrumentation Air Supply Filter Regulator Rattling
- AR 3974224; Valve Will Not Move in Either Direction
- AR 3974228; OPS 4.0 Critique for U1 Scram on Generator Lockout
- AR 3974244; 1B21–F070 Found with Packing Leak
- AR 3974329; GC Leak on Rectifier Bank 2
- AR 3975069; Revise LOP–AP–01
- AR 3975195; ISO-Phase Bus Duct Extent of Condition
- AR 3975195; ISO-Phase Bus Duct Extent of Condition
- AR 3975576; 1FW005 Feed Reg Valve Positioner Arm Broken
- AR 3975651; OPS 4.0 Critique for U1 Scram on High Reactor Water Level
- CC–AA–5001; Engineering Department Start-Up Checklist; 1/24/2017
- IR 3965520; Post Transient Review—BWR, Stator Water Cooling System Transient Required Manual Scram; 1/23/2017
- IR 3965520; Post Transient Review—BWR; Event Date 1/23/2017
- IR 3965520; Post Transient Review—BWR; Unit 2 Transient Within the Stator Water Cooling System Resulting in Manual SCRAM; 1/23/2017
- IR 3975051; Extent of Condition for U2 IPBD Following L1F44
- IR 3975571; Event Report—Unit 1 Trip on Failure of Feed Regulating Valve (FRV) 1FW005;
- IR 3975571; Post Transient Review—BWR; (Event Date) 2/17/2017
- L1F44; Forced Outage Activity Listing; 2/17/2017
- L1F44–001; Scope Change Request (Addition); 2/14/2017
- L1F44–002; Outage Execution Scope Add Sheet; 2/15/2017
- L2F4S; HLA Briefing Worksheet for Startup (L2F4S); 1/2017
- LAS–1–2017–0094, IR 3973724; Risk Assessment, ODM: L1F44 Iso-Phase; Revision 0
- LaSalle County Station, Operator Log; 1/23/2017
- LOA–FW–101; Reactor Level/Feedwater Pump Control Trouble; Revision 11
- LOR–1H13–P601–A108; RX Vessel WTR LVL 8 HI; Alarm 1HP22A; Revision 5
- LOR–1H13–P603–A309; FW Control RX Vessel LVL 7 HI; Alarm 1FW20A; Revision 2
- Memo from Terry Lance to Harold Vinyard; L1F45 PORC Start-Up Review for Plant Manager's Approval to Startup Unit 1; 2/18/2017
- NF–LA–715; Critical Prediction Checklist; 2/15/2017
- Operators Log, Unit 2 Trip; 1/23/2017
- PORC 17–008; L1F44 Start-Up; 2/15/2017
- Seq. ID SAr5.0; Control Rod Sequence Review and Approval for L1F44 Start-Up; 2/15/2017
- Unit 2 MCR Panel Walk Down List; 2H13–P601 Alarms; 1/23/2017
- Unit 2 NSO S.E.R. Alarm Summary Log; 1/23/2017

4OA5 Other Activities

- AR 3987848; NRC Feedback from Temporary Inspection 2515/192
- LOA–AP–101; Unit 1, AC Power System Abnormal; Revision 55
- LOR–1PM01J–A314; 4KV Bus 141S/Y Undervoltage 4KV Bus 141Y Degraded Voltage, Revision 9
- LOR–1PM01J–A404; System Auxiliary Transformer 142 Loss of Phase; Revision 4
- LOR–2PM01J–A505; System Auxiliary Transformer 242 Loss of Phase Relay Trouble; Revision 2
- LOS–AP–W1; Switchyard Weekly Inspection; Revision 29

- OE 12–001; Operability Evaluation: Potential Vulnerability in Switchyard Single Open Phase Detection (IR 1322688); Revision 0
- OP–LA–1010–111–1002; LaSalle Operations Philosophy Handbook; Revision 69
- PI–AA–126–1005–F–01; Check in Self-Assessment; Revision 1

LIST OF ACRONYMS USED

ALARA	As-Low-As-Is-Reasonably-Achievable
ANS	Alert and Notification System
AR	Action Request (Issue Report)
ASME	American Society of Mechanical Engineers
CAP	Corrective Action Program
CCDP	Conditional Core Damage Probability
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
CSCS	Core Standby Cooling System
DG	Diesel Generator
ET	Exposure Time
EP	Emergency Preparedness
ERO	Emergency Response Organization
FIF	Fire Ignition Frequency
HPCS	High Pressure Core Spray
IMC	Inspection Manual Chapter
IP	Inspection Procedure
LERF	Large Early Release Frequency
LOOP	Loss of Off-Site Power
MCB	Main Control Board
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
OPC	Open Phase Condition
PI	Performance Indicator
PM	Preventative Maintenance
PMT	Post Maintenance Testing
RCIC	Reactor Core Isolation Cooling
RHR	Residual Heat Removal
SPAR	Standardized Plant Analysis Risk
SAPHIRE	Systems Analysis Programs for Hands-On Integrated Reliability Evaluations
SSC	Structure, System, or Component
TI	Temporary Instruction
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
UT	Ultrasonic Examination
WO	Work Order