November 9, 2007

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

SUBJECT: LASALLE COUNTY STATION, UNITS 1 AND 2
NRC COMPONENT DESIGN BASIS INSPECTION REPORT
05000373/2007009(DRS); 05000374/2007009(DRS)

Dear Mr. Crane:

On September 28, 2007, the U. S. Nuclear Regulatory Commission (NRC) completed a biennial component design basis baseline inspection at your LaSalle County Station, Units 1 and 2. The enclosed report documents the inspection findings, which were discussed on September 28, 2007, with the Site Engineering Director, Mr. J. Bashor and other members of your staff.

This inspection examined activities conducted under your license as they relate to safety and to compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected calculations, design bases documents, procedures, and records; observed activities; and interviewed personnel. Specifically, this inspection focused on the design of components that were risk significant and had low margin.

Based on the results of this inspection, four NRC-identified findings of very low safety significance were identified, all of which involved violations of NRC requirements. However, because these violations were of very low safety significance and because they were entered into your corrective action program, the NRC is treating the issues as Non-Cited Violations in accordance with Section VI.A.1 of the NRC's Enforcement Policy.

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

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

Sincerely,

/RA/

Ann Marie Stone, Chief
Engineering Branch 2
Division of Reactor Safety

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

Enclosure: Inspection Report 05000373/2007009(DRS); 05000374/2007009(DRS)
w/Attachment: Supplemental Information

cc w/encl: Site Vice President - LaSalle County Station
LaSalle County Station Plant Manager
Regulatory Assurance Manager - LaSalle County Station
Chief Operating Officer
Senior Vice President - Nuclear Services
Senior Vice President - Mid-West Regional Operating Group
Vice President - Mid-West Operations Support
Vice President - Licensing and Regulatory Affairs
Director Licensing - Mid-West Regional Operating Group
Manager Licensing - Clinton and LaSalle
Senior Counsel, Nuclear, Mid-West Regional Operating Group
Document Control Desk - Licensing
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Illinois Emergency Management Agency
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Chairman, Illinois Commerce Commission

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Director Licensing - Mid-West Regional Operating Group
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Inspection Report to Mr. C. Crane from Ms. A. M. Stone dated November 9, 2007

SUBJECT: LASALLE COUNTY STATION, UNITS 1 AND 2
NRC COMPONENT DESIGN BASIS INSPECTION REPORT
05000373/2007009(DRS); 05000374/2007009(DRS)

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REGION III

Docket Nos:	50-373; 50-374
License Nos:	NPF-11; NPF-18
Report Nos.:	05000373/2007009; 05000374/2007009
Licensee:	Exelon Generation Company, LLC
Facility:	LaSalle County Station, Units 1 and 2
Location:	Marseilles IL, 66666
Dates:	August 27 through September 28, 2007
Inspectors:	P. Lougheed, Senior Engineering Inspector, Lead G. Hausman, Senior Engineering Inspector N. Valos, Senior Operations Examiner C. Acosta Acevedo, Engineering Inspector N. Feliz Adorno, Engineering Inspector C. Baron, Mechanical Contractor G. Nicely, Electrical Contractor
Approved by:	A.M. Stone, Chief Engineering Branch 2 Division of Reactor Safety

SUMMARY OF FINDINGS

IR 05000373/2007009, 05000374/2007009; 08/27/07 - 09/28/07; LaSalle County Station, Units 1 and 2; Component Design Basis Inspection.

The inspection was a 3-week onsite baseline inspection that focused on the design of components that are risk significant and have low design margin. The inspection was conducted by regional engineering inspectors and two consultants. Four findings of very low safety significance were identified, all with associated Non-Cited Violations (NCVs). The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, “Significance Determination Process (SDP).” Findings for which the SDP does not apply may be Green, or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, “Reactor Oversight Process,” Revision 3; dated July 2000.

A. Inspector-Identified and Self-Revealed Findings

Cornerstone: Mitigating Systems

- Green. The inspectors identified a finding of very low safety significance and an associated NCV of the LaSalle County Station Facility Operating License associated with the Fire Protection Program for failure to ensure that all necessary testing was identified and performed. Specifically, the licensee failed to periodically test remote-local keylock control switches on the switchgear for the emergency buses which are required to implement a safe shutdown for a plant fire in accordance with the licensee’s Safe Shutdown Analysis described in Appendix H, Section H.4 of the Fire Protection Report. This issue was entered into the licensee’s corrective action program, and as a compensatory measure, the licensee implemented procedure changes to the safe shutdown procedures that gave direction to manually close a breaker if the breaker failed to close using the remote-local keylock switch. The licensee also successfully tested a portion of the remote-local switches and initiated efforts to determine a schedule for testing of the remaining keylock switches.

  The finding was more than minor because the licensee did not ensure the operability and functional performance of the remote-local keylock control switches to perform satisfactorily in service. The finding was of very low safety significance based on the results of a Phase 1 screening completed in accordance with IMC 0609, Appendix F, “Fire Protection Significant Determination Process.” The inspectors determined that there was no cross-cutting aspect to this finding. (Section 1R21.3.b.1)

- Green. The inspectors identified an NCV of 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” in that, the design bases for the manual backwash valve position values for the Diesel Generator Cooling Water (DGCW) backwash strainers were not correctly translated into procedures and instructions. Specifically, the manual backwash valve positions derived from flow test surveillance procedures based on hydraulic calculation models were not translated into operations procedures for manual operation of the DGCW strainer backwash valves. This issue was entered into the licensee's corrective action program, and the licensee updated the applicable operating procedure to reflect the correct manual settings for the DGCW strainer backwash valves.

This issue was more than minor because the DGCW backwash valves could be manually opened more than required during a loss of power event, and thus divert some cooling flow from post accident required equipment. The finding was of very low safety significance based on a Phase 1 screening in accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," because on re-evaluation, the design function was maintained. The cause of the finding is related to the cross-cutting element of Human Performance, Resources, because the licensee failed to have complete, accurate, and up-to-date procedures (H.2(c)). (Section 1R21.3.b.2)

- Green. A finding of very low safety significance was identified by the inspectors associated with a Non-Cited Violation of 10 CFR 50.63, "Loss of All Alternating Current Power." Specifically, the licensee did not have an appropriate analysis to determine the capability of coping with a station blackout, in that, it had no analysis that verified the proper operation of the reactor core isolation cooling (RCIC) turbine at the elevated suppression pool temperatures encountered during a station blackout event. This issue was entered into the licensee's corrective action program. The licensee obtained additional information and performed a preliminary analysis which showed that the RCIC turbine would operate as required.

  This finding was more than minor because the licensee did not have an analysis that demonstrated the availability and reliability of the RCIC turbine at the elevated suppression pool temperatures encountered during a station blackout event. The issue was of very low safety significance based on a Phase 1 screening in accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situation," because the licensee obtained additional data from the RCIC turbine manufacturer and performed a functionality analysis which demonstrated the pump turbine could operate at heightened suppression pool temperatures. The inspectors determined that there was no cross-cutting aspect to this finding. (Section 1R21.3.b.3)

- Severity Level IV. The inspectors identified an NCV of 10 CFR Part 50.59, "Changes, Tests, and Experiments," which had very low safety significance. Specifically, the licensee failed to complete a 50.59 evaluation for removing main control room lake level instrumentation from service. Although the UFSAR stated that the lake level was continuously monitored in the main control room, the level instrument had not functioned reliably for several years and was removed from the plant maintenance schedule in December 2005. At the time of the inspection, control room monitoring of the lake level was not available. The licensee entered the issue into their corrective action program and initiated more frequent operator rounds as a compensatory measure.

  The finding was more than minor because the inspectors could not reasonably determine that this change would not have ultimately required prior approval from the NRC. This finding was categorized as Severity Level IV because the underlying technical issue for the finding was determined to be of very low safety significance based on a Phase 1 screening in accordance with IMC 0609, Appendix A, “Significance Determination of Reactor Inspection Findings for At-Power Situation.” The inspectors concluded that this finding was cross-cutting in the area of Human Performance, Resources, because the licensee failed to effectively address a long standing equipment issue (H.2(a)). (Section 1R21.3.b.4)

B. <u>Licensee-Identified Violations</u>

None

REPORT DETAILS

1. REACTOR SAFETY

Cornerstone: Initiating Events, Mitigating Systems, and Barrier Integrity

1R21 Component Design Bases Inspection (71111.21)

.1 Introduction

The objective of the component design bases inspection is to verify that design bases have been correctly implemented for the selected risk significant components and that operating procedures and operator actions are consistent with design and licensing bases. As plants age, their design bases may be difficult to determine and an important design feature may be altered or disabled during a modification. The Probabilistic Risk Assessment (PRA) model assumes the capability of safety systems and components to perform their intended safety function successfully. This inspectible area verifies aspects of the Initiating Events, Mitigating Systems, and Barrier Integrity cornerstones for which there are no indicators to measure performance.

Specific documents reviewed during the inspection are listed in the attachment to the report.

.2 Inspection Sample Selection Process

The inspectors selected risk significant components and operator actions for review using information contained in the licensee's 2006B PRA Model. In general, the selection was based upon the components and operator actions having a risk achievement worth of greater than 2.0. The operator actions selected for review included actions taken by operators both inside and outside of the control room during postulated accident scenarios.

The inspectors performed a margin assessment and detailed review of the selected risk-significant components to verify that the design bases have been correctly implemented and maintained. This design margin assessment considered original design reductions caused by design modification, or power uprates, or reductions due to degraded material condition. Equipment reliability issues were also considered in the selection of components for detailed review. These included items such as performance test results, significant corrective action, repeated maintenance activities, maintenance rule (a)(1) status, components requiring an operability evaluation, NRC resident inspector input of problem areas/equipment, and system health reports. Consideration was also given to the uniqueness and complexity of the design, operating experience, and the available defense in depth margins. A summary of the reviews performed and the specific inspection findings identified are included in the following sections of the report.

.3 <u>Component Design</u>

a. <u>Inspection Scope</u>

The inspectors reviewed the Updated Final Safety Analysis Report (UFSAR), Technical Specifications (TS), design basis documents, drawings, calculations and other available design basis information, to determine the performance requirements of the selected components. The inspectors used applicable industry standards, such as the American Society of Mechanical Engineers (ASME) Code, Institute of Electrical and Electronics Engineers Standards and the National Electric Code, to evaluate acceptability of the systems' design. The NRC also evaluated licensee actions, if any, taken in response to NRC issued operating experience, such as Bulletins, Generic Letters (GLs) and Information Notices (INs). The review was to verify that the selected components would function as designed when required and support proper operation of the associated systems. The attributes that were needed for a component to perform its required function included process medium, energy sources, control systems, operator actions, and heat removal. The attributes to verify that the component condition and tested capability was consistent with the design bases and was appropriate may include installed configuration, system operation, detailed design, system testing, equipment and environmental qualification, equipment protection, component inputs and outputs, operating experience, and component degradation.

For each of the components selected, the inspectors reviewed the maintenance history, system health reports, operating experience-related information and licensee corrective action program documents. Field walkdowns were conducted for all accessible components to assess material condition and to verify that the as-built condition was consistent with the design. Other attributes reviewed are included as part of the scope for each individual component.

The following 17 Unit 1 and Unit 2 components were reviewed (17 inspection samples):

1. <u>4160V Switchgear 241Y (2AP04E, Unit 2, Division 1)</u>: The inspectors reviewed selected calculations for electrical distribution system load flow/voltage drop, degraded voltage protection, short-circuit, and electrical protection and coordination. The adequacy and appropriateness of design assumptions and calculations were reviewed to verify that bus capacity was not exceeded and bus voltages remained above minimum acceptable values under design basis conditions. The switchgear's protective device settings and breaker ratings were reviewed to ensure that selective coordination was adequate for protection of connected equipment during worst-case short-circuit conditions. Automatic and manual transfer schemes between alternate offsite sources and the shared emergency diesel generator (i.e., Unit 0) were reviewed. To ensure that adequate margin existed for design basis events with a loss of offsite power, the emergency diesel generator's steady-state loading calculations were reviewed. Voltage protection schemes were reviewed for degraded and loss of voltage relaying. The inspectors verified that degraded and loss of voltage relays were set in accordance with calculations, and that associated calibration procedures were consistent with calculation assumptions, associated time delays and set-point accuracy calculations. In addition, the latest surveillance was reviewed. The inspectors evaluated selected portions of the licensee response to NRC Generic Letter (GL) 2006-02,

"Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated February 1, 2006. The station's interface and coordination with the transmission system operator for plant voltage requirements and notification set-points were reviewed. The inspectors reviewed the adequacy of instrumentation/alarms available. To ensure that breakers were maintained in accordance with industry and vendor recommendations, the inspectors reviewed the preventive maintenance inspection and testing procedures. Switchgear and breaker failure history was also reviewed. The inspectors reviewed the operating procedures for normal, abnormal, and emergency conditions. The breaker closure and opening control logic diagrams and the 125Vdc voltage calculations were reviewed to ensure adequate voltage would be available for the control circuit components and the breaker spring charging motors. The inspectors performed a visual non-intrusive inspection of observable portions of the safety-related 4160V switchgear to assess the installation configuration, material condition, and potential vulnerability to hazards.

2. <u>480V Switchgear 235X (2AP19E, Unit 2, Division 1)</u>: The inspectors reviewed selected calculations for electrical distribution system load flow/voltage drop, short-circuit, and electrical protection and coordination. The adequacy and appropriateness of design assumptions and calculations were reviewed to verify that bus capacity was not exceeded and bus voltages remained above minimum acceptable values under design basis conditions. The switchgear's protective device settings and breaker ratings were reviewed to ensure that selective coordination was adequate for protection of connected equipment during worst-case short-circuit conditions. The inspectors reviewed the voltage protection scheme and the adequacy of instrumentation/alarms available. To ensure that breakers were maintained in accordance with industry and vendor recommendations, the inspectors reviewed the preventive maintenance inspection and testing procedures. Switchgear and breaker failure history was also reviewed. The inspectors reviewed the operating procedures for normal, abnormal, and emergency conditions. The breaker closure and opening control logic diagrams and the 125Vdc voltage calculations were reviewed to ensure adequate voltage would be available for the control circuit components. The inspectors performed a visual non-intrusive inspection of observable portions of the safety-related 480Vac switchgear to assess the installation configuration, material condition, and potential vulnerability to hazards.

3. <u>4160/480V Stepdown Transformer 235X (Unit 2, Division 1)</u>: The inspectors assessed the sizing, loading, protection, and voltage taps for the 4160V/480V transformer 235X to ensure adequate voltage to the 480V Switchgear 235X. The inspectors reviewed the ampacity for the source and load side feeder cables. The inspectors reviewed the protective device settings to ensure that the feeder cables and transformer was protected in accordance with industry standards. A review of the testing requirements, preventive maintenance, failure history, and instrumentation/alarms was performed. The inspectors performed a visual non-intrusive inspection of observable portions of the transformer to assess the installation configuration, material condition, and potential vulnerability to hazards.

4. Battery 2DC07E (Unit 2, Division 1): The inspectors reviewed electrical calculations including battery sizing, duty cycle, voltage drop calculations, short-circuit fault current calculation, breaker interrupting ratings and electrical coordination, battery float and equalizing voltages. In addition, the voltage drop calculations for safety-related dc loads and dc control power to 4160V and 480V switchgear were evaluated to verify that adequate voltage was available at these loads during a design bases event with loss of offsite power and for a station blackout event. The inspectors verified minimum and maximum battery room temperatures and hydrogen buildup calculations for consistency with design basis requirements. The inspectors reviewed the 125Vdc ground detection system including the ground sensitivity and basis for alarms and action levels. The operating procedures for normal, abnormal, and emergency conditions were reviewed. The inspectors reviewed WO 00620342, "Replace Unit 2 Div 1 Battery During L2R10," dated July 29, 2004, to ensure that the installation was consistent with vendor recommendations and design bases requirements, including post-modification testing. A review of the testing requirements, preventive maintenance, failure history, and instrumentation/alarms was performed. The inspectors also reviewed the overall battery capacity, latest modified performance discharge test and service test, and quarterly battery surveillance tests required by technical specifications. The inspectors performed a visual non-intrusive inspection of observable portions of the batteries to assess the installation configuration, material condition, and potential vulnerability to hazards.

5. Battery Charger 2DC09E (Unit 2, Division 1): The inspectors reviewed electrical calculations for the 125Vdc battery charger 2DC09E, including sizing calculation, contribution to short-circuit fault current, and breaker sizing. The operating procedures for normal, abnormal, and emergency conditions were reviewed. In addition, the test procedures were reviewed to determine if maintenance and testing activities for the battery chargers were in accordance with UFSAR requirements and vendor recommendations. The inspectors reviewed engineering change EC 333821, "Installation of new backup battery chargers for the 125Vdc Division 1 and 2 batteries," Revision 0, to ensure technical adequacy and consistency with design requirements. The inspectors performed a visual non-intrusive inspection of the battery chargers to assess the installation configuration, material condition, and potential vulnerability to hazards.

6. Diesel Generator Cooling Water Pump 0DG01P (Non-unitized, Division 1): The inspectors reviewed calculations to verify net positive suction head requirements to ensure the pump was capable of performing its safety functions. Hydraulic calculations were reviewed to ensure design requirements for flow and pressure were appropriately translated into acceptance criteria used in pump surveillances and to verify the pump would perform under worst case design conditions. The inspectors reviewed associated electrical calculations to confirm that the design basis minimum voltage at the motor terminals would be adequate for starting and running the motor under design basis conditions. The protective device/thermal overload relay settings were reviewed to ensure that adequate margin existed. A review of the cable's ampacity was performed and evaluated to determine if adequate margin was available for all motor operating conditions. The inspectors reviewed the breaker closure and opening control logic diagrams and the control circuit voltage calculations to ensure adequate voltage would be available for the

control circuit components. Design change history and surveillance results were reviewed to assess potential component degradation and impact on design margins. The ultimate heat sink condition was also reviewed (temperature limits and water volume requirements including silt levels) and the associated flow paths to ensure that the water source design basis was maintained.

7. Diesel Generator Cooling Water Strainer 0DG01F (Non-unitized, Division 1): The inspectors reviewed set-point and set-point basis for strainer delta-P alarm and auto-backwash initiation to ensure unimpeded flow. Corrective actions, surveillance results, and trending data were reviewed to assess potential component degradation and impact on design margins. Operating procedures for manual strainer backwash were also reviewed to ensure unimpeded flow following a loss of power. Particle retention capability was verified to meet design basis.

8. Northwest Room Cooler 2VY01C (Unit 2, Division 1): The inspectors reviewed thermal performance analysis for room cooler with maximum water temperature and post-accident room temperature calculations to ensure the cooler was capable of performing its required function under worst case design conditions. This review included fouling, heat transfer capacity, heat load, and process medium (air and water). The inspectors reviewed associated electrical calculations to confirm that the design basis minimum voltage at the motor terminals would be adequate for starting and running the motor under design basis conditions. The protective device/thermal overload relay settings were reviewed to ensure that adequate margin existed. A review of the cable's ampacity was performed and evaluated to determine if adequate margin was available for all motor operating conditions. The inspectors reviewed the breaker closure and opening control logic diagrams and the control circuit voltage calculations to ensure adequate voltage would be available for the control circuit components. Corrective actions and surveillance results were reviewed to verify acceptance criteria were met and performance degradation would be identified.

9. Residual Heat Removal Service Water (RHRSW) Pumps 2E12-C300A & B (Unit 2, Division 1): The inspectors reviewed piping and instrumentation diagrams, pump line up, and pump capacities for the RHRSW pumps, specifically 2E12-C300A & B. Design calculations related to pump head, minimum required flow, and net positive suction head were reviewed to ensure the pumps were capable of providing their accident mitigation function during all ambient conditions. The inspectors reviewed associated electrical calculations to confirm that the design basis minimum voltage at the motor terminals would be adequate for starting and running the motor under design basis conditions. The protective device relay settings were reviewed to ensure that adequate margin existed. A review of the cable's ampacity was performed and evaluated to determine if adequate margin was available for all motor operating conditions. The inspectors reviewed the breaker closure and opening control logic diagrams and the 125Vdc voltage calculations to ensure adequate voltage would be available for the control circuit components. Design change history, corrective actions, surveillance results, and trending data were reviewed to assess potential component degradation and impact on design margins including water-hammer, cavitation, and vibration. The ultimate heat sink condition was also reviewed (temperature limits and water volume requirements including silt

levels) and the associated flow paths to ensure that the water source design basis was maintained.

10. RHRSW Strainer 2E12-D300A (Unit 2, Division 1): The inspectors reviewed set−point and set-point basis for strainer delta-P alarm and auto-backwash initiation to ensure unimpeded flow. Corrective actions, surveillance results, and trending data were reviewed to assess potential component degradation and impact on design margins. Operating procedures for manual strainer backwash were also reviewed to ensure unimpeded flow following a loss of power. Particle retention capability was verified to meet design basis.

11. Residual Heat Removal (RHR) Pump 2E12-C002A (Unit 2, Division 1): The inspectors reviewed piping and instrumentation diagrams, pump line up, pump capacities, and surveillance procedures and data for the RHR pumps. Design calculations related to pump head, minimum required flow, net positive suction head (NPSH) were reviewed to ensure the pumps were capable of providing their accident mitigation function during all ambient conditions. The inspectors reviewed associated electrical calculations to confirm that the design basis minimum voltage at the motor terminals would be adequate for starting and running the motor under design basis conditions. The protective device relay settings were reviewed to ensure that adequate margin existed. A review of the cable's ampacity was performed and evaluated to determine if adequate margin was available for all motor operating conditions. For the RHR pump motor, the inspectors assessed the bases for brake horsepower values used as design inputs to the licensee's electrical calculations. The inspectors reviewed the breaker closure and opening control logic diagrams and the 125Vdc voltage calculations to ensure adequate voltage would be available for the control circuit components. Design change history was also reviewed to assess potential component degradation and impact on design margins.

12. RHR Suppression Pool Strainer 2E12-D301A (Unit 2, Division 1): The inspectors reviewed the design specifications preventive maintenance tasks, corrective maintenance history, problem history, including records of inspections of the drywell and the suppression pool. The inspectors also reviewed procedures, surveillances, operating history and differential pressure and debris loading calculations to ensure the strainers were capable of performing their required functions under required conditions.

13. High Pressure Core Spray (HPCS) Pump 2E22-C001 (Unit 2, Division 1): The inspectors reviewed the system hydraulic and NPSH analysis, the basis for the pump inservice test acceptance criteria, and a sample of actual inservice test results to verify the capability of the pump to perform its design function under accident conditions. The inspectors reviewed the input to the accident analyses regarding the performance of the HPCS system to verify the system performance was bounding. The inspectors reviewed associated electrical calculations to confirm that the design basis minimum voltage at the motor terminals would be adequate for starting and running the motor under design basis conditions. The protective device/thermal overload relay settings were reviewed to ensure that adequate margin existed. A review of the cable's ampacity was performed and evaluated to determine if adequate margin was available for all motor operating

conditions. The inspectors reviewed the breaker closure and opening control logic diagrams and the 125Vdc voltage calculations to ensure adequate voltage would be available for the control circuit components. In addition, the inspectors performed a walkdown of the HPCS pump and reviewed the pump control logic including the automatic initiation logic and the control of the associated automatic injection valve. Both normal and emergency operating procedures associated with the pump were also reviewed. Both normal and emergency operating procedures associated with the pump were also reviewed.

14. <u>High Pressure Core Spray Minimum Flow Valve 2E22-F012 (Unit 2, Division 1)</u>: The inspectors reviewed the motor operated valve analysis and testing, the basis for the valve test acceptance criteria, and a sample of actual test results to verify the capability of the valve to perform its design function under accident conditions. The bases for the setpoints to open and close the valve during pump operation were reviewed. The inspectors reviewed the one line and schematic diagrams. The inspectors reviewed associated electrical calculations to confirm that the design basis minimum voltage at the motor terminals would be adequate for starting and running the motor under design basis conditions. The protective device/thermal overload relay settings were reviewed to ensure that adequate margin existed. A review of the cable's ampacity was performed and evaluated to determine if adequate margin was available for all motor operating conditions. The inspectors reviewed the breaker closure and opening control logic diagrams and the control circuit voltage calculations to ensure adequate voltage would be available for the control circuit components. The inspectors performed a walkdown of the valve. The inspectors reviewed the licensee's response to NRC Bulletin 88-04, regarding minimum HPCS flow. The inspectors also reviewed a modification which affected the valve gear ratio and stroke time. In addition, the inspectors reviewed the valve control logic. Both normal and emergency operating procedures associated with the pump were also reviewed.

15. <u>Inboard Main Steam Isolation Valves 1B21-FO22A & D (Unit 1, Division 1 & 2)</u>: The inspectors reviewed the preventive maintenance tasks, corrective maintenance history, problem history, and operating history to ensure the valves were capable of performing their required functions under required conditions. The inspectors reviewed the motor-operated valve (MOV) calculations, including required thrust, accumulator sizing and maximum differential pressure, to ensure the valve was capable of functioning under design conditions. Functional test and leak rate test results were reviewed to verify acceptance criteria were met and performance degradation would be identified. The inspectors also reviewed operational procedures, the control logic schematic diagrams, the system description, and flow control diagrams to verify the adequacy of valve control logic design and to ensure that the valve was capable of functioning under design conditions.

16. <u>Reactor Building Closed Cooling Water (RBCCW) Outboard Containment Isolation Valve 2WR040 (Unit 2, Division 1)</u>: The inspectors reviewed the licensing basis for this RBCCW containment isolation valve. The review included the motor operated valve analysis and testing, the basis for the valve test acceptance criteria, including leakage limits, and a sample of actual test results to verify the capability of the valve to perform its design function under accident conditions. The inspectors reviewed the one-line and schematic diagrams. The inspectors reviewed

associated electrical calculations to confirm that the design basis minimum voltage at the motor terminals would be adequate for starting and running the motor under design basis conditions. The protective device/thermal overload relay settings were reviewed to ensure that adequate margin existed. A review of the cable's ampacity was performed and evaluated to determine if adequate margin was available for all motor operating conditions. The inspectors reviewed the breaker closure and opening control logic diagrams and the control circuit voltage calculations to ensure adequate voltage would be available for the control circuit components. The inspectors performed a walkdown of the valve. In addition, the inspectors reviewed the valve control logic. Both normal and emergency operating procedures associated with the pump were also reviewed.

17. <u>Circulating Water System Discharge Aramco Gate 2CW082 (Unit 2, Non−divisional)</u>: The inspectors reviewed the function of the circulating water system discharge gate with regard to its function to terminate a potential internal plant flood. The inspectors' review included the operating procedures associated with operating the gate under both normal and abnormal conditions. The inspectors also performed a walkdown of the gate including the actions that would be required if electrical power was not available. The inspectors also reviewed the maintenance procedures and motor operator setting information associated with the gate.

b. <u>Findings</u>

1. <u>Failure to Periodically Test Keylock Switches</u>

<u>Introduction</u>: The inspectors identified a finding of very low safety significance and an associated NCV of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control" for failure to ensure that all testing, necessary to demonstrate that components required to implement a safe shutdown for a plant fire would perform satisfactorily in service, was identified and performed. Specifically, the licensee failed to periodically test remote-local keylock control switches on the switchgear for the emergency buses which could be required to implement a safe shutdown for a plant fire in accordance with the licensee's Safe Shutdown Analysis described in Appendix H, Section H.4 of the Fire Protection Report.

<u>Description</u>: On August 27, 2007, during a plant walkdown of selected plant components, the inspectors questioned whether the remote-local keylock control switches on the switchgear for the emergency buses were periodically tested per station procedures. The response obtained was that no testing of the switchgear remote-local keylock control switches was periodically performed and that cycling of the switches was not routinely performed.

The inspectors determined that procedures LOA-FX-101, "Unit 1 Safe Shutdown with a Loss of Offsite Power <u>AND</u> a Fire in the Control Room or AEER [Auxiliary Electrical Equipment Room]," and LOA-FX-201, "Unit 2 Safe Shutdown with a Loss of Offsite Power <u>AND</u> a Fire in the Control Room or AEER," required the use of the remote-local keylock control switches. In addition, certain support procedures referenced from LOA-FX-101 and LOA-FX-201 required the use of the remote-local keylock control switches.

The inspectors reviewed the licensee's post-fire safe shutdown analysis (SSA) described in Appendix H, Section H.4 of the Fire Protection Report (FPR). The SSA credits local control capability (e.g., local pump starts or local switchgear breaker closures for certain switchgear breakers), since fires in the Main Control Room or Division 1 or Division 2 AEER could affect certain equipment (e.g., auxiliary control panels 1(2) PM01J in the Main Control Room) required for safe shutdown of the reactor during a loss of offsite power event.

The existing circuitry for the 23 remote-local keylock control switches associated with the FPR SSA was installed and tested as modifications in October and November 1989 for Unit 1 and in April 1990 for Unit 2. The switches allow local control of the associated safe shutdown equipment, independent of the Main Control Room, in the event of a fire in the Main Control Room, Division 1 AEER, or Division 2 AEER.

Following completion of the modifications, the switches were tested using modification tests. However, the inspectors determined that no subsequent periodic testing of the remote-local keylock control switches had been performed since the performance of the modification tests.

To provide a measure of assurance that the remote-local keylock control switches would operate satisfactorily if required, the licensee initiated testing of the keylock switches that could be tested with the Units at power. The licensee satisfactorily tested 5 of the keylock switches prior to the end of the inspection, and initiated efforts to determine a schedule for testing of the remaining 18 keylock switches, some of the which could not be tested with the Units at power.

Analysis: The inspectors determined that failure to periodically test these remote-local keylock control switches was a performance deficiency warranting a significance evaluation. The inspectors determined the finding was more than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening" because the finding was associated with the equipment performance attribute of the Mitigating Systems Cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, the licensee did not ensure the operability and functional performance of the remote-local keylock control switches to perform satisfactorily in service.

The inspectors completed a significance determination of this issue using IMC 0609, Appendix F, "Fire Protection Significant Determination Process." The inspectors determined that the finding screened as having very low safety significance (Green) during the Fire Protection SDP Phase 1 screening, because the issue had a LOW degradation rating, since the performance and reliability of the affected post-fire safe shutdown equipment was expected to be minimally impacted by the lack of periodic testing of the remote-local keylock control switches due to successful completion of a sample of the keylock switches (5 of 23), and compensatory measures instituted to provide direction on how to manual close a breaker if the local control device failed to close the breaker. The inspectors determined that there was no cross-cutting aspect to this finding.

Enforcement: Facility Operating License condition 2.C.(25) for Unit 1 and Facility Operating License condition 2.C.(15) for Unit 2, required, in part, that the licensee implement and maintain all provisions of the approved Fire Protection Program as described in the Final Safety Analysis Report for the facility, and as approved in

NUREG-0519, “Safety Evaluation Report (SER) related to the operation of LaSalle County Station, Units 1 and 2,” dated March 1981. Section 17, “Quality Assurance,” of the SER, stated, in part, that the quality assurance (QA) program for the operations phase of the facility was described in Section 17 of the Final Safety Analysis Report, and that the quality assurance program for the operations phase complied with 10 CFR Part 50, Appendix B.

Chapter 17, “Quality Assurance,” of the Updated Final Safety Analysis Report (UFSAR), stated, in part, that the Exelon Generation Company (EGC) Quality Assurance Topical Report is the basis for the QA Program at LaSalle County Station. Section 2.4 of the EGC Quality Assurance Topical Report stated, in part, that routine testing of fire protection systems assures reliability and that the QA program for the fire protection structures, systems, and components ensures that testing meets the applicable QA guidelines described in the applicable Branch Technical Position (BTP) 9.5-1. Section C.4 of BTP .5-1 stated, in part, that the licensee’s QA program for the fire protection program be part of the overall plant QA program and that it satisfies the criterion for “Test Control.”

Title 10 CFR Part 50, Appendix B, Criterion XI, “Test Control” requires, in part, that a test program shall be established to assure that all testing required to demonstrate that structures, systems, and components will perform satisfactorily in service be identified and performed.

Contrary to 10 CFR Part 50, Appendix B, Criteria XI, “Test Control,” from November 1989 for Unit 1, and from April 1990 for Unit 2, following modification installation of the revised circuitry for the remote-local keylock control switches, to August 28, 2007, the licensee’s test program failed to ensure that all testing, necessary to demonstrate that certain Unit 1 and 2 components required to implement a safe shutdown for a plant fire would perform satisfactorily in service, was identified and performed. Specifically, the licensee failed to periodically test remote-local keylock control switches on the switchgear for the emergency buses required to implement a safe shutdown for a plant fire in accordance with the licensee’s Safe Shutdown Analysis. This finding applies to both units. However, because this violation was of very low safety significance and because the issue was entered into the licensee’s corrective action program (IR 00666945), this violation is being treated as a NCV consistent with Section VI.A.1 of the NRC Enforcement Policy.
(NCV 05000373/2007009-01, NCV 05000374/2007009-01)

2. Failure to Translate Backwash Valve Settings into Procedures

Introduction: The inspectors identified an NCV of 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” having very low safety significance (Green), in that, the design bases for the required manual setting for the Diesel Generator Cooling Water (DGCW) backwash valves were not correctly translated into procedures and instructions. Specifically, the manual backwash valve positions derived from flow test surveillance procedures based on hydraulic calculation models were not correctly translated into operations procedures for manual operation of the DGCW strainer backwash valves.

Description: On August 28, 2007, the inspectors identified inconsistencies in the manual backwash valve positions for the DGCW strainers listed in operating procedure LOP-DG-04, “Diesel Generator Special Operations,” and quarterly operations surveillance procedures LOS-DG-Q1, “0 Diesel Generator Auxiliaries Test,” LOS-DG-Q2, “1A(2A) Diesel Generator Auxiliaries Test,” and LOS-DG-Q3, “1B(2B)

Diesel Generator Auxiliaries Test." The manual backwash valve positions were to be derived from the flow test surveillance procedures LOS-DG-SR5, "0 DG Cooling Water System Flow Test," LOS-DG-SR6, "Division 2 Cooling Water System Test," and LOS-DG-SR7, "Division 3 Cooling Water System Test." If the backwash flow was found outside the acceptable flow band, a limit switch adjustment was made to the motor-operated backwash valve. The limit switch set-point should be converted into the number of hand turns open on the strainer backwash valve, and procedures LOP-DG 04, and LOS-DG-Q1, LOS-DG-Q2, and LOS-DG-Q3 updated as necessary to ensure that the correct valve position value was used when manually backwashing the strainers. However, there was no process to ensure that, following an adjustment of a limit switch to a backwash valve, the required changes to procedures LOP-DG-04, and LOS-DG-Q1, LOS-DG-Q2, and LOS-DG-Q3 were actually performed.

The licensee initiated IR 00665626 and performed a prompt operability assessment of the discrepancies. Based on the test case evaluation using a hydraulic model, with an increase in backwash flow by a factor of two, the impact on Diesel Generator (DG) coolers was approximately a 20 gpm reduction in flow, and the impact on the Emergency Core Cooling System (ECCS) cubicle room coolers (i.e., VY coolers) was approximately a 5 gpm reduction. Based on operability limits specified in engineering calculation EC 360691, Revision 0, "CSCS Cooling Water Flow Margins for Operability of the ECCS Cubicle Room Coolers and DG Coolers," there was at least a 400 gpm margin for the 1A (2A) DG coolers, and at least a 50 gpm margin for the 1(2)VY03A coolers. Therefore, the licensee concluded that adequate margin existed to ensure that the DG and VY system heat exchangers were capable of performing their design function even with the increased strainer backwash flows produced by manual backwash.

The licensee updated procedure LOP-DG-04, "Diesel Generator Special Operations," on August 29, 2007, to Revision 43, to reflect the correct manual settings for the DGCW strainer backwash valves. The licensee planned to update the quarterly operations surveillance procedures prior to the next scheduled surveillance which uses these procedures.

Analysis: The inspectors determined that failure to control the manual setting for the DGCW backwash valves to ensure their design function during accident conditions was a performance deficiency warranting a significance evaluation in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Disposition Screening." This issue was more than minor because the finding was associated with the procedure quality attribute of the Mitigating System cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of the DGCW system to respond to initiating events to prevent undesirable consequences. Specifically, the DGCW backwash valves could be manually opened more than required during a loss of power event, and thus divert some cooling flow from post accident required equipment.

The inspectors evaluated the finding using IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," Phase 1 screening. The inspectors answered "No" to all the screening questions because re-evaluation confirmed the operability of the system. Therefore, the finding screened as having very low safety significance (Green). The inspectors also determined that this finding was cross-cutting in the area of Human Performance, resources in that the licensee failed to have complete, accurate, and up-to-date procedures (H.2(c)). Specifically, several operating and quarterly surveillance procedures were not updated when adjustments were made to the DGCW backwash valves' limit switches during performance of the system flow tests.

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, "Design Control" requires, in part, that measures be established to assure that applicable regulatory requirements and the design basis are correctly translated into procedures and instructions.

Contrary to this requirement, prior to August 28, 2007, the licensee had not established effective measures to ensure that the design basis for the required manual setting for the DGCW backwash valves was correctly translated into procedures and instructions. Specifically, the manual backwash valve positions derived from flow test surveillance procedures based on hydraulic calculation models were not translated into operations procedures for manual operation of the DGCW strainer backwash valves. This finding applies to both units. However, because this violation was of very low safety significance and because the issue was entered into the licensee's corrective action program (IR 00665626), this violation is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy. (NCV 05000373/2007009-02, NCV 05000374/2007009-02)

3. Lack of Station Blackout Analysis for Reactor Core Isolation Cooling (RCIC)

Introduction: The inspectors identified an NCV of 10 CFR 50.63, "Loss of All Alternating Current Power" having very low safety significance (Green). Specifically, the licensee did not have an appropriate analysis to determine the capability of coping with a station blackout in that it had no analysis that verified the proper operation of the RCIC turbine at the elevated suppression pool temperatures encountered during a station blackout event.

Description: While reviewing the engineering evaluation for the effect of power uprate on the Station Blackout Coping Assessment (NDIT No. LAS-ENDIT-1255), the inspectors observed that the peak suppression pool temperature predicted during a station blackout event was 196°F. The inspectors noted that emergency operating procedure LGA-001, "RPV Control," Revision 7 had the following caution statement regarding RCIC "CAUTION: Exceeding 180°F lube oil temperature may cause system damage." Since the RCIC lube oil temperature would be higher than the suppression pool temperature (as it is cooled by the suppression pool), the inspectors were concerned that the RCIC turbine would not be able to perform its required function during a station blackout at these heightened suppression pool temperatures, such that the RCIC turbine could fail during a station blackout leaving the plant without its primary means of maintaining reactor coolant inventory.

Based upon the inspectors' concerns, the licensee further researched the issue and discovered that the licensee did not have an established basis for the operation of the RCIC turbine above 180°F. The issue was entered into the licensee's corrective action program as Issue Report (IR) 00673099. The licensee performed a prompt operability assessment and also addressed the availability and reliability of the RCIC turbine during station blackout conditions. This condition was also applicable to an Appendix R event. However, since the Appendix R event duration was shorter than the assumed duration for the station blackout event, the suppression pool temperature evaluation for station blackout was found to be more limiting than that of the Appendix R event.

The licensee contacted the original equipment manufacturer for the LaSalle RCIC turbine (now Dresser-Rand). Dresser-Rand provided a letter dated September 21, 2007 that gave temperature limits for short time operation (approximately 3 hours) for the RCIC turbine supplied to the station. The licensee used the letter from Dresser-Rand regarding the temperature limits for the RCIC turbine, and performed a preliminary analysis that concluded that the RCIC turbine would operate properly for the heightened suppression pool temperatures achieved during station blackout conditions. The licensee planned to perform a more detailed analysis to calculate the maximum suppression pool temperature that would limit the oil temperature to the bearing temperature limit.

While the licensee was ultimately able to determine the availability and reliability of the RCIC turbine during the elevated suppression pool temperatures encountered during a station blackout, the licensee's existing design basis had not been adequate. Prior to the inspectors' questioning the operation of the RCIC turbine above 180°F lube oil temperature, the licensee did not have an analysis that supported the proper operation of the RCIC turbine at elevated suppression pool temperatures during a station blackout event.

Analysis: The team determined that the failure to have an appropriate analysis to determine the capability of coping with a station blackout was a performance deficiency warranting a significance evaluation in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Disposition Screening." The cause was reasonably within the licensee's ability to foresee and correct and it could have been prevented because the licensee had an opportunity to identify the issue in 2000 when reviewing calculations for the power uprate amendment.

The issue was determined to be more than minor because it was associated with the equipment performance attribute of the Mitigating Systems cornerstone. Specifically, the licensee did not have an analysis that demonstrated the availability and reliability of the RCIC turbine at the elevated suppression pool temperatures encountered during a station blackout event. The inspectors evaluated the finding using IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," Phase 1 screening. The inspectors answered "No" to all the screening questions in the Mitigating System Cornerstone Column because the licensee obtained additional data from the RCIC turbine manufacturer and performed a functionality analysis which demonstrated the pump turbine could operate at heightened suppression pool temperatures. The finding screened as having very low safety significance (Green). The inspectors determined that there was no cross-cutting aspect to this finding.

Enforcement: Title 10 CFR 50.63, "Loss of All Alternating Current Power," Paragraph (a)(2) requires, in part, that licensees provide sufficient capacity and capability to ensure the core is cooled in the event of a station blackout for the specified duration. It further requires that the capability for coping with a station blackout of specified duration shall be determined by an appropriate coping analysis. Finally, it requires that licensees have the baseline assumptions, analyses, and related information used in their coping evaluations available for NRC review.

Contrary to the above, as of September 19, 2007, the licensee failed to have an appropriate coping analysis which determined the capability of the RCIC turbine to operate during a station blackout event. Specifically, the licensee failed to have an analysis which verified that the appropriate operation of the RCIC turbine at the elevated suppression pool temperatures encountered during a station blackout. However, because this violation was of very low safety significance and because the issue was entered into the licensee's corrective action program (IR 00673099), this violation is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000373/2007009-03; 05000374/2007009-03).

4. <u>Lake Level Instrumentation Removed from Service without 10 CFR 50.59 Evaluation</u>

<u>Introduction:</u> The inspectors identified an NCV of 10 CFR 50.59, "Changes, Tests, and Experiments," which had very low safety significance. Specifically, the licensee failed to complete a 50.59 evaluation for removing main control room lake level instrumentation from service. Although the UFSAR stated that the lake level was continuously monitored in the main control room, the inspectors determined that the instrument had been abandoned, and that an evaluation had not been completed as required by 10 CFR 50.59.

<u>Description:</u> The inspectors reviewed UFSAR section 2.4.8.1, which stated in part, "Lake level is continuously monitored in the main control room of the power plant." The inspectors questioned the status of the main control room lake level instrumentation and determined that it had been problematic for several years and had not functioned since 2005. The inspectors questioned how the operators would detect a failure of the dike, resulting in a loss of lake level, with sufficient time to shut-off non-safety related pumps and preserve the required ultimate heat sink inventory.

In response to these questions, the licensee provided calculation WR-LS-UH-2, Revision 0, which concluded that the failure of a large dike section could result in the ultimate heat sink level being reached in approximately 4.5 hours. The licensee also stated that the lake level was locally verified by operator rounds once per shift (8 hours). In addition, the licensee stated that it was likely that they would be informed of a major dike failure by other means. The inspectors determined that these were not adequate measures to ensure a timely response to a potential loss of the ultimate heat sink.

The licensee stated that in September 2003, a Reasonable Assurance of Safety evaluation had been performed for continued operation with the main control room instrumentation not functional. The licensee's review of plant maintenance records indicated that the last time the lake level instrument was functional was in June 2005, and that the instrument was removed from the plant maintenance schedule in December 2005. In April 2006, the Plant Health Committee recommended abandoning the instrument and initiated engineering change EC 360580. At the time of the inspection, EC 360580 was in progress, and no 10 CFR 50.59 evaluation had yet been completed.

During the inspection, the licensee initiated IR 00674071 to address this condition. The recommended actions included compensatory measures to verify lake level every 3 hours, a work request to repair the instrument, and actions to prevent a similar condition in the future. The compensatory measures to verify lake level every 3 hours were implemented on September 24, 2007.

<u>Analysis:</u> The inspectors determined that removing the lake level instrument from service without a 10 CFR 50.59 evaluation was a performance deficiency. The inspectors concluded that the violation was reasonably within the licensee's ability to foresee and correct based on the procedures in effect at the time.

Because violations of 10 CFR 50.59 are considered to be violations that potentially impede or impact the regulatory process, they are dispositioned under the traditional enforcement process instead of the SDP. However, if possible, the underlying technical issue is evaluated under the SDP to determine the severity of the violation. The finding was determined to be more than minor because the inspectors could not reasonably determine that this change would not have ultimately required prior approval from the NRC. The inspectors completed a significance determination of the underlying technical issue using IMC 0609, Appendix A. The inspectors determined the finding impacted the Mitigating System cornerstone and using the Phase 1 screening worksheet, concluded the finding was of very low safety significance (green) because it did not result in a loss of functionality of any mitigating systems.

The inspectors concluded that this finding was cross-cutting in the area of Human Performance, Resources, because the licensee failed to effectively address a long standing equipment issue (H.2(a)). Specifically, the lake level instrumentation was non-functional for an extended period of time and this degraded condition was accepted by the licensee.

Enforcement: Title 10 CFR 50.59 stated, in part, that a licensee shall obtain a license amendment pursuant to Section 50.90 prior to implementing a proposed change, test, or experiment if the change, test, or experiment would create a possibility for a malfunction of a component important to safety with a different result than any previously evaluated in the final safety analysis report (as updated). Contrary to the above, in December 2005, the licensee abandoned instrumentation described in the safety analysis report without a 10 CFR 50.59 evaluation. The failure to maintain this instrument could have affected licensee’s ability to ensure a timely response to a potential loss of the ultimate heat sink. In accordance with the Enforcement Policy, the violation was classified as a Severity Level IV violation because the underlying technical issue was of very low risk significance. Because this non-willful violation was non-repetitive and was captured in the licensee’s corrective action program as IR 00674071, this violation is being treated as a Non-Cited Violation consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000373/2007009-04; 05000374/2007009-04).

5. Exclusion of Potential Internal Flood Sources Under 10 CFR 50.59

Introduction: The inspectors identified an Unresolved Item (URI) concerning changes to the licensee’s flooding analyses.

Description: The original licensing basis assumed all gravity fed flood sources were installed within watertight barriers. In 1995, the licensee determined that several non-safety related, non-seismically designed piping sections in the turbine building had the potential of allowing a gravity fed internal flood from the lake. This flood could potentially communicate with vital areas in the auxiliary building and reactor building, affecting multiple trains of safety related equipment required for safe shutdown. The licensee performed evaluations of these piping sections and determined that their failure was not credible. Based on these evaluations, the licensee revised the UFSAR without prior NRC approval under 10 CFR 50.59.

The inspectors reviewed documentation associated with the “crack exclusion” of sections of moderate energy piping in the turbine building. An Operability Assessment Process Form

(PIF 373-201-95-00260), dated March 21, 1995, addressed a non-conformance with UFSAR Section 3.4.1.4.a, which stated that gravity flooding due to pipe rupture in the turbine building would be confined to watertight enclosures. Walkdowns had identified several sections of non-safety related, non-seismically designed piping that were not within watertight enclosures. A gravity fed flood from the lake could potentially result in flooding of the turbine building up to the maximum lake level of 701 feet. This flood level could potentially communicate with vital areas in the auxiliary building and reactor building, affecting multiple trains of safety related equipment required for safe shutdown.

The licensee performed an evaluation to justify continued operation of the units. This evaluation determined that pipe cracks need not be postulated for any piping for which the normal operating pressure is less than 10 psig, based on Appendix J of the UFSAR (Appendix J defined moderate energy piping as being greater than 10 psig). The evaluation also determined that pipe cracks need not be postulated for any moderate energy piping that meet the pipe stress criteria of Standard Review Plan (SRP) 3.6.2. An associated 10 CFR 50.59 evaluation, dated March 21, 1995, determined that no unreviewed safety question (USQ) existed.

A UFSAR change request (LU1999-032), dated May 26, 1999 was issued to revise the UFSAR to include both the 10 psig and SRP 3.6.2 "crack exclusion" criteria. This change also included a 10 CRF 50.59 evaluation (L99-126), dated May 20, 1999, which concluded that no USQ existed. The inspectors also noted that both these 10 CFR 50.59 evaluations stated that if a pipe crack was to occur, sufficient time would be available to isolate the flood source. In response to the inspectors' questions, the licensee stated that the capability to isolate these floods had not been verified.

The inspectors questioned if these 10 CFR 50.59 evaluations had been adequate to make these licensing basis changes without prior NRC approval. The original license was based on a determination that potential gravity flooding due to failure of non-safety related, non-seismically designed piping in the turbine building would be confined to watertight enclosures, and that safety related equipment was located above the maximum water level. The inspectors were concerned that the identification of non-safety related, non-seismically designed piping outside of the watertight enclosures created the possibility for an accident or malfunction of a different type than any evaluated previously in the safety analysis report. Flooding from a potential rupture of this piping could affect safety-related equipment that is located below normal lake level.

In response to NRC concerns, the licensee documented this issue in IR 676923, "CDBI−NRC Identified Flooding Methodology as URI." The licensee maintained that piping with an internal pressure less that 10 psi did not have to be evaluated, since it was not evaluated in the initial license application. This item is considered unresolved pending further NRC evaluation of the licensee's licensing basis. (URI 05000373/2007009-05; 05000374/2007009-05).

.4 Operating Experience

a. Inspection Scope

The inspectors reviewed six operating experience issues (6 samples) to ensure that NRC generic concerns had been adequately evaluated and addressed by the licensee. The operating experience issues listed below were reviewed as part of this inspection:

- Bulletin 1988-04, Potential Safety-Related Pump Loss;
- GL 2006-02, Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power;
- IN 1996-48, Motor-Operated Valve Performance Issues;
- IN 2005-30, Safe Shutdown Potentially Challenged by Unanalyzed Internal Flooding Events and Inadequate Design;
- IN 2006-26: Failure of Magnesium Rotors in Motor Operated Valve Actuators; and
- IN 2006-31: Inadequate Fault Interrupting Rating of Breakers.

b. Findings

No findings of significance were identified.

.5 Modifications

a. Inspection Scope

The inspectors reviewed five permanent plant modifications related to selected risk significant components to verify that the design bases, licensing bases, and performance capability of the components had not been degraded through modifications. The modifications listed below were reviewed as part of this inspection effort:

- EC 333821 Install Backup Unit 2 Division 1 125VDC Battery Charger;
- EC 341950 Elimination of RHRSW Keepfill;
- EC 347065 RHRSW Orifice 1E12-D304B Resizing;
- EC 348851 Change Overall Gear Ratio for Valve 1E22-F012; and
- EC 359114 Replace Thermocouple with RTD on Temperature Elements 2TE-CW010 and 2TE-CW011.

b. Findings

No findings of significance were identified.

.6 Risk Significant Operator Actions

a. Inspection Scope

The inspectors performed a margin assessment and detailed review of five risk significant, time critical operator actions (5 samples). These actions were selected from the licensee's PRA rankings of human action importance based on risk achievement worth values. Where possible, margins were determined by the review of the assumed design basis and

UFSAR response times and performance times documented by job performance measures results. For the selected operator actions, the inspectors performed a detailed review and walk through of associated procedures, including observing the performance of some actions in the station's simulator and in the plant for other actions, with an appropriate plant operator to assess operator knowledge level, adequacy of procedures, and availability of special equipment where required.

The following operator actions were reviewed:

- Operator Fails to Open 2-inch Vent to Maintain Drywell Pressure;
- Operator Fails to Shed 125V DC Non-Essential Loads;
- Operator Fails to Manually Initiate Suppression Pool Cooling and Manipulate Valves;
- Operator Fails to Bypass Emergency Diesel Generator 0 Output Breaker Interlocks; and
- Operator Fails to Throttle Operating Residual Heat Removal Service Water Pump Given Failure of Paired Pump.

b. Findings

No findings of significance were identified.

4OA6 Meeting(s)

Exit Meeting

The inspectors presented the inspection results to Mr. J. Bashor and other members of licensee management at the conclusion of the inspection on September 28, 2007. The inspectors asked the licensee whether any of the material examined during the inspection should be considered proprietary. No proprietary information was identified.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee
D. Enright, Site Vice President
D. Rhoades, Plant Manager
J. Bashor, Site Engineering Director
R. Ebright, Training Director
H. Vinyard, Acting Operations Director
B. Ginter, Programs Engineering Manager
F. Gogliotti, Plant Engineering Manager
J. Rappeport, Nuclear Oversight Manager
J. Rommel, Design Engineering Manager
T. Simpkin, Regulatory Assurance Manager
V. Shah, Electrical Design Engineering Supervisor
P. Holland, Regulatory Assurance Engineer

Nuclear Regulatory Commission
A. M. Stone, Chief, Engineering Branch 2
D. Kimble, Senior Resident Inspector

LIST OF ITEMS OPENED, DISCUSSED, AND CLOSED

Opened and Closed

05000373/2007009-01 05000374/2007009-01	NCV	Failure to Periodically Test Keylock Switches (Section 1R21.3.b.1)
05000373/2007009-02 05000374/2007009-02	NCV	Failure to Translate Backwash Valve Settings into Procedures (Section 1R21.3.b.2)
05000373/2007009-03 05000374/2007009-03	NCV	Lack of Station Blackout Analysis for RCIC (Section 1R21.3.b.3)
05000373/2007009-04 05000374/2007009-04	NCV	Lake Level Instrumentation Removed from Service without 10 CFR 50.59 Evaluation (Section 1R21.3.b.4)

Opened

05000373/2007009-05 05000374/2007009-05	URI	Exclusion of Potential Internal Flood Sources Under 10 CFR 50.59

Discussed

None

LIST OF DOCUMENTS REVIEWED

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

CALCULATIONS

Number	Description or Title	Date or Revision
004-E-019-WR	MOV Terminal Voltage Calc	002
4266/19AQ08	4160v Bus Available Fault Current During Diesel Generator Testing	000A
4266/19AZ29	120VAC Control Circuit Maximum Allowable Cable Lengths	0
4266/19AZ31	Calculation For Degraded Voltage With A 2.5 Percent Boost At The Div ½ Unit Substation Transformers	000A
4266/19AZ34	Div 1 480V MCC Control Circuit Lengths	0
4266/19AZ37	Div 3 480V MCC Control Circuit Lengths	1
4266/19D27	125V Div 1 Battery Sizing	11
4266/19G-5	Power Cable Ampacities	1
97-200	VY Cooler Thermal Performance Model – 1(2)VY01A and 1(2)VY02A	1
AK-19	DG Loading Calc - Input KW Loading on 4160 Swgr 141Y, 142Y, and 242Y	007H
AN30	MOV Replacement	002
AN71	Second Level Undervoltage Relay Setpoint	002B
AOV-MEDP-LAS-MS-001	Unit 1 Inboard MSIV, 1B21-F022A/B/C/D, Maximum Expected Differential Pressure	December 10, 2003
ATD-0070	Limiting Operating Conditions for NPSH for HPCS, LPCS, RCIC, and RHR Pumps	2
CQD-053566	Seismic Qualification of Switchgear with Racked Out Breakers	00
D20	Tabulation of DC Loads for ELMS	4F
D27	125V Division 1 Battery Sizing	012C
D30	Station Blackout - Capability of 125V and 250V Batteries to Feed Loads during Station Blackout	005B
D34	125V DC System - Short Circuit	1
D36	125VDC and 250VDC Battery Inter-Cell Connector Resistance	001
D4	Sizing Battery Chargers for 125V GNB NCX-17 Batteries 2A, 2B	103
D50	Division 1, 2, & 3 125Vdc Switchgear Breaker	003B

CALCULATIONS

Number	Description or Title	Date or Revision
	Control Voltage Adequacy	
EAD-3	Low Voltage Circuit Breaker Settings And Coordination Curves	005A
EAD-4	Relay Settings For 4.16kv Safety Related Busses	001A
EC 0000336218	Determination of Approximate Uncertainty of CW Inlet Temperature	April 2, 2002
EQ-01	Temperature and Humidity Profile for the ECCS Pump Cubicles	1
L-000295	Analysis Of Safety-Related Loads During LOCA Block Start For Lasalle Unit 2	002C
L-000296	Assessment of Unit 2 Protective Device Operation for S/R Loads During LOCA Block-Start	002B
L-000317	MCC Settings for Continuous Duty Motors	1
L-000718	Determination Of Potential Water Hammer Forces At The RHR Heat Exchanger From A Postulated RHRSW Void Formation	2
L-000731	Evaluation of the RHR Heat Exchanger for Water Hammer Effect	3
L-001078	RHR Pump A Cubicle Cooler Ventilation System	1
L-001196	HPCS Pump Discharge Pressure Indication Accuracy During Surveillance Testing Under Normal Conditions	0
L-001249	Determination of Allowable Pressure Drop for ECCS Suction Strainers	0, 4
L-001355	Hydraulic Analysis	4
L-001780	RHR Heat Exchanger – Cooling Water Orifice E12-D304A/B	2
L-001891	125Vdc Battery Cross Tie Capability & Diesel Generators 0, 1(2)A, 1(2)B, Air Start Solenoid Voltage Adequacy	002B
L-002051	ECCS Strainer Head Loss Performance Analysis	2, 4
L-002276	Calculation of the HPCS, LPCS, and LPCI Minimum Pump Head to Meet the LOCA Analysis Assumptions	0A
L-002404	CSCS Cooling Water System Road Map	
L-002540	NPSH Margin for HPCS, RHR, and RCIC Pumps, Backpressure for RCIC Turbine	1A
L-002588	Loss Of Voltage Relay Setpoint 4.16kv Buses - Undervoltage Function	001C

CALCULATIONS

Number	Description or Title	Date or Revision
L-002589	Instrument Setpoint Analysis For 4.16kv Undervoltage Relay - Time Delay Function	001B
L-002591	Instrument Setpoint Analysis For 4.16kv Degraded Voltage Relays	001A
L-002749	Evaluation of ESF 125VDC Battery with a Jumpered Battery Cell - 57 Cells	000E
L-002756	Main Steam Isolation Valve Actuator Sizing Assessment	1
L-002958	125VDC, 250VDC, 24/48VDC DC System Calculation Overview	000A
L-002968	DC System Ground Detector Action Levels	0
L-002993	RHR SW Div. 2 Keep Fill Elimination – Piping Fluid Temperature and Reroute Elevation	0
L-003230	CW Inlet Temperature Uncertainty Analysis	1
L-003311	4kV SWGR Spring Charging Motor Terminal Voltage Calculation	0
LAS-2E22-F012	AC Motor Operated Gate Valve Calculation	4
LAS-2WR-040	AC Motor Operated Gate Valve Calc - 2WR040	004
LAS-2WR-040	AC Motor Operated Gate Valve Calculation	4
LAS-NPD-95-0015	Moderate Energy Pipe Break Evaluations in Diesel and Turbine/Auxiliary Buildings	1
NED-I-EIC-0198	HPCS, LPCS, and LPCI Discharge Min Flow Bypass Differential Pressure Switch Setpoint Error	1F
P99-019	Document The Re-Baseline Of Vibration And Differential Pressure Acceptance Criteria	April 6, 1999
SEAG 0005310592	LaSalle RHR Heat Exchanger Postulated Water hammer	October 11, 1996
VX-09	Battery Rooms Hydrogen Concentration	12A
WR-LS-UH-2	Effect of Peripheral Dike Failure	0

CORRECTIVE ACTION PROGRAM DOCUMENTS ISSUED DURING INSPECTION

Number	Description or Title	Date or Revision
663629	Update Calculations for New UHS Temperature Limit	August 23, 2007
665256	CDBI Initial Walkdown Results	August 27, 2007
665626	CDBI-NRC Identified Inconsistencies in DGCWP B/W Vlv Pos	August 28, 2007
666030	CDBI – NRC ID 2E12-F336A Packing Leak Needs WO	August 29, 2007
666322	NRC ID: CDBI Block Start Effects Not Analyzed	August 30, 2007
666431	CDBI – NRC ID Typo in LOS-DG-SR5	August 30, 2007
666534	CDBI: (NRC) NED-I-EIC-0198 Has Minor	August 30, 2007

CORRECTIVE ACTION PROGRAM DOCUMENTS ISSUED DURING INSPECTION

Number	Description or Title	Date or Revision
	Discrepancy	
666787	CDBI- Time to Open Control Panel Doors in SBO LOAs	August 31, 2007
668215	CDBI - Calc D50 Lacks Spring Charging Motor Evaluation	September 5, 2007
668422	CDBI – NRC Identified Enhancement Required in LOA-AP-101/201	August 31, 2007
670520	CDBI Water Hammer Calculation Temperature Assumption	September 12, 2007
670659	NRC Identified errors in battery installation procedure	September 12, 2007
670828	CDBI: NRC Identified Minor Discrepancies in Calculation L-003230	September 13, 2007
671107	2DC07E Inter-rack terminal plate connection	September 13, 2007
672166	NRC Identified Minor Discrepancies in Calc L-002591	September 17, 2007
672299	NRC CDBI ID'D: Procedure LTS-600-41 Incorrect Prerequisite	September 17, 2007
672675	CDBI-2DC07E Battery Post Torque Values	September 18, 2007
673099	CDBI-RCIC Ops with Elevated Suppression Pool Temps	September 19, 2007
674071	CDBI – Main Control Room Lake Level Indication	September 21, 2007
674696	CDBI-HPCS Pump Suction Strainer	September 26, 2007
674874	Enhancements to Procedure ER-AA-335-1006	September 24, 2007
674975	CDBI NRC Identified Missing Reference in LOP-DC-01	September 24, 2007
675316	CDBI: DEE Perform One-Time Review of UHS Temperature As-Found Data	September 25, 2007
675576	CDBI-Control of Crack Excluded CW/SW Piping in Turb. Bld.	September 25, 2007
675980	CDBI Related-LOA-AP-101/102 Needs Revision	September 29, 2007
676923	CDBI- NRC Identified Flooding Methodology as URI	September 28, 2007

CORRECTIVE ACTION PROGRAM DOCUMENTS REVIEWED

Number	Description or Title	Date or Revision
00274430	T&D State Estimator Program Uses Only Real-Time SAT Loading	November 17, 2004
00275156-07	Address INPO SY Visit Recommendation	November 17, 2004
00324289	AC MOV Rotor Bar Degradation	April 13, 2005
00346255	Trip of 241Y Cubicle 4 Feed to 235X/Y	June 22, 2005
00348105	Degradation of Blowdown Flow Instrumentation	June 27, 2005
00359972	Document Operability for the Population of	August 4, 2005

CORRECTIVE ACTION PROGRAM DOCUMENTS REVIEWED

Number	Description or Title	Date or Revision
	GR-5 Relays	
00369406	2A RHR WS Strainer High DP on System Shutdown	September 01, 2005
00382871	Extent of Condition Review of ECCS Pump Cubicle Calculations	October 6, 2005
00487036	2A RHR Pump Seal Cooler Cleaning Needs to be Moved Up	May 5, 2006
00493959	NRC Identified UFSAR/Procedure Clarifications Required	May 25, 2006
00519938	UFSAR Compliance	August 15, 2006
00522883	Outdated VY Room Cooler Calculations	August 23, 2006
00548208	0DG Strainer D/P High Alarmed During LOS-DG-M1	October 24, 2006
00553004	2A RHR Seal Cooler Test Delayed Due to Controlotron Issues	November 3, 2006
00563051	2E12-F336A Packing Leak - Minor	November 29, 2006
00563833	Inconsistencies in the FSAR	August 30, 2006
00564045	Adverse Vibration Trend on 2E12-C002A	December 1, 2006
00595903	2E12-C300B 100 DPM Inner Bearing Seal Leak	February 26, 2007
00601311	CSCS Strainer 2E12-D300A had area below min wall	March 9, 2007
00644128	Required Flow for IST Data Not Met	June 25, 2007
00655363	CDBI - Recalculate MOV Voltages at Accident Temperatures	July 30, 2007

DRAWINGS

Number	Description or Title	Date or Revision
	Instrument Loop Sketch of Units 1 and 2 RTDs to Monitor “CW” Inlet Temperature of Ultimate Heat Sink	
1-71-04-30971-D1	Setting Plan/Outline Drawing for 52 I.D. RHR Heat Exchanger	11
1-71-04-30971-D5	Bundle details for RHR Heat Exchanger	5
1E-0-4401S	Relaying and Metering - Standby DG 0	V
1E-0-4412AB	4160V Swgr 241Y DG 0 Schematic	AA
1E-0-4412AH	DG 0 Generator/Engine Control Schematic	R
1E-1-4232AT	Primary Containment & Reactor Vessel Isolation System	S
1E-2-3330	Electrical Installation Turbine Building Plan Elevation 687’-0” Columns 21 – 25 & U - W	AA
1E-2-3331	Electrical Installation Turbine Building Plan	AE

DRAWINGS

Number	Description or Title	Date or Revision
	Elevation 687'-0" Columns 18 – 21 & U - W	
1E-2-3334	Electrical Installation Turbine Building Plan Elevation 687'-0" Columns 21 – 25 & R - U	E
1E-2-4000A	Single Line Diagram - Generator, Transformers, & 6900V Buses Part 1	P
1E-2-4000AK	Key Diagram - 4160V SWGR 241Y	D
1E-2-4000B	Single Line Diagram - Stand-by Generators & 4160V Buses Part 2	L
1E-2-4000BN	Key Diagram - 480V SWGR 235X	C
1E-2-4000CT	Key Diagram - 480V MCCs 235X-1 & 235X-2	AL
1E-2-4000CU	Key Diagram - 480V MCC 235X-3	S
1E-2-4000D	Single Line Diagram - 480V Substations on SWGR 241X/241Y	A
1E-2-4000DB	Station Key Diagram - 125V DC Distribution System	H
1E-2-4000FB	Key Diagram - 125V DC Distribution ESS Div 1	N
1E-2-4000M	Station Key Diagram - 6900V & 4160V SWGRS	E
1E-2-4000N	Station Key Diagram - 480V SWGRS PT 1	K
1E-2-4000N	Station Key Diagram - 480V SWGRS PT 2	H
1E-2-4000PG	Relaying & Metering Diagram - 4160V SWGR 241Y	W
1E-2-4000RJ	Relaying & Metering Diagram - 480V SWGR 235X/235Y	E
1E-2-4005AJ	Schematic Diagram 4160V Switchgear 241Y Main Feed ACB 2412 System "AP" Part 9	N
1E-2-4005AM	Schematic Diagram 4160V Switchgear 241Y Auxiliary Compartment System "AP" Part 12	K
1E-2-4005BC	Schematic Diagram - 4160V SWGR 241Y Feed to Transformer 235X/235Y	G
1E-2-4005BQ	Schematic Diagram 480V Switchgears 235X & 235Y Main Feeders System "AP" Part 39	F
1E-2-4005BR	Schematic Diagram 480V Switchgears 235X & 235Y Under-voltage Relays System "AP" Part 40	F
1E-2-4022ZC	Loop Schematic Diagram Circulating Water System "CW" Part 3	E
1E-2-4088AF	Schematic Diagram Switchgear Heat Removal Alarms System "VX" Part 6	F
1E-2-4088AG	Schematic Diagram Switchgear Heat Removal System "VX" Part 7	F
1E-2-4089AA	Schematic Diagram Core Standby Cooling System "VY" Part 1	E
1E-2-4089AD	Schematic Diagram Core Standby Cooling Alarms System "VY" Part 4	D

DRAWINGS

Number	Description or Title	Date or Revision
1E-2-4089AE	Schematic Diagram Core Standby Cooling System "VY" Part 5	B
1E-2-4096AB	Schematic Diagram - RB Closed Cooling Water System	G
1E-2-4220AE	Schematic Diagram Residual Heat Removal System "RH" (E12) Part 5	G
1E-2-4220AH	RHR System Schematic	W
1E-2-4220AR	Schematic Diagram Residual Heat Removal Alarms System "RH" (E12) Part 16	O
1E-2-4222AB	Schematic Diagram High Pressure Core Spray System "HP" (E22A) Part. 2	S
1E-2-4222AC	Schematic Diagram High Pressure Core Spray System "HP" (E22A) Part. 3	N
1E-2-4222AD	Schematic Diagram High Pressure Core Spray System "HP" (E22A) Part. 4	P
1E-2-4222AE	Schematic Diagram High Pressure Core Spray System "HP" (E22A) Part. 5	N
1E-2-4223AA	Schematic Diagram High Pressure Core Spray Diesel Generation "2B" Alarms System "HP" (E22B) Part. 1	V
DG-9	DG 0 Output Breaker Logic	1
LSL2-ECCS-8006-1100	Sure-Flow Strainer ECCS Strainer Assembly	October 7, 1997
M-55	P&ID Main Steam	November 6, 2000
M-63	P&ID - Circulating Water System	AO
M-765, Sheet 4	Circulating Water Piping	M
M-90	P&ID - Reactor Building Closed Cooling Water	W
M-95	P&ID - High Pressure Core Spray	AM
M-1061	Miscellaneous Accumulators Section – 3	G
M-2063, Sheet 1	P&ID/C&I Details Circulating Water System - CW	B
M-3465, Sheet 2	HVAC C&I Detail Diagram	C
PD-422884	Flote-Flow Balanced Stop Valve	October 18, 1992
Q1646-00	CSCS Watertight Door Specification	
S0-556469	Diagram Of Connections - 58 NCX-17 On Two Step Racks And Rack Arrangement	A
VPF-2993-419	Performance Test Curve for 2E12-C002A	1

MODIFICATIONS

Number	Description or Title	Date or Revision
DCP 9700547	ECCS Suction Strainer Replacement - HPCS	March 25, 1998
DCP 9900038	Replace Blowdown Flow Instrument Telemetry System	January 27, 1999
EC 051415	Wiring Change to 0 DG Cooling Water Strainer	0
EC 333821	Installation Of New Backup Battery Chargers For The 125Vdc Division 1 And 2 Batteries	0
EC 339456,	R. P. Adams Automatic Poro-Edge Water Strainers Attachment A	July 9, 1996
EC 341950	Unit 1 RHR WS Keep Fill Elimination – Project SCSE82	4
EC 347065	RHR Service Water Div. 2 Orifice 1E12-D304B Resizing due to EC 341950	6
EC 347827	Alternate Design for CSCS Pumps (RHR Service Water and DG Cooling Water Pumps)	0
EC 348851	1E22-F012 Valve Motor/Gearing Change	0
EC 352940	Pipe Min Wall for PMIDS 173621 to 173628	0
EC 359114	Replace T/C with RTD On 2TE-CW010 and 2TE-CW011	0, 1, 2 & 3
EC 359524	DGSW Pump Replacement Design Summary	0
EC 360691	CSCS Cooling Water Flow Margins for Operability of the ECCS Cubicle Room Coolers and DG Coolers	0
EC 367084	Assessment of NPSH Margin for CSCS Pumps	0
EC 367382	Evaluation on the 2A RHR PP Seal Cooler Service Water Flow Degradation (IR 667189)	September 14, 2007
WO 00620342	Replace Unit 2 Div 1 Battery During L2R10	July 29, 2004

PROCEDURES

Number	Description or Title	Date or Revision
CC-AA-205	Control of Undocumented/Unqualified Coatings Inside the Containment	4
ER-AA-330-008	Exelon Service Level I, and Safety-Related (Service Level III) Protective Coatings	5
ER-AA-335-1006	Heat Exchanger Electromagnetic Testing (ET) Methodology	2
LAP-400-20	Primary Containment Debris Material Control Program	1

PROCEDURES

Number	Description or Title	Date or Revision
LEP-AP-05	GE 480V switchgear cleaning and inspection	8
LES-DC-101A	Division 1 125V Battery Inspection for Units 1 and 2	13
LES-DC-103A	Division 1 Battery Charger Capacity Test	15
LEP-DC-105	Installation of Division 1 Batteries	12
LES-GM-109	Inspection of 480V Klockner-Moeller MCC	33
LGA-RH-201	Alternate Vessel Injection Using Shutdown Cooling Return	2
LIP-VY-501A	Unit 1 A RHR Pump Room Cooler Fan Temperature Switch (Div 1) Calibration	5
LIP-VY-601A	Unit 2 A RHR Pump Room Cooler Fan Temperature Switch (Div 1) Calibration	5
LIS-WL-001	Lake Level, Temperature, and Blowdown Flow Indication Calibration	5
LOA-AP-201	Unit 2, AC Power System Abnormal	24
LOA-CW-201	Unit 2 Circulating Water System Abnormal	13
LOA-FLD-001	Flooding	9
LOA-PC-201	Primary/Secondary Containment Trouble	13
LOP-CW-03	Startup and Operation of Circulating Water System	31
LOP-DC-01	Battery Charger Startup and Shutdown	31
LOP-DG-02	Diesel Generator Startup and Operation	43
LOP-DG-04	Diesel Generator Special Operations	43
LOP-HP-03	Preparation for Standby Operation of High Pressure Core Spray System (HPCS)	19
LOP-VX-02	Switchgear Heat Removal System Shutdown	13
LOS-AA-S101	Unit 1 Shiftly Surveillance	44
LOS-HP-M1	High Pressure Core Spray System Operability Test	15
LOS-HP-Q1	HPCS System Test	55
LOS-HP-Q2	HPCS Valve Test	18
LOS-PC-Q2	Primary Containment Isolation Valves Operability Test and Inspection for Modes 4, 5 or Defueled	46
LOS-RH-M1	RHR System and RHR WS System Operability Test for Mode 1, 2, 3, 4 and 5	21
LOS-RH-Q1	RHR and RHR Service Water Pump and Valve In-service Test for Modes 1, 2, 3, 4 and 5	65
LOS-RH-R1	LPCI Injection Line Check Valve In-service Test	14
LOS-RP-Q3	Main Steam Isolation Valve Scram Functional Test	16
LTS-100-3	Main Steam Isolation Valve Local Leak Rate Test	18
LTS-100-30	RBCCW Containment Isolation Valves Local	20

PROCEDURES

Number	Description or Title	Date or Revision
	Leak Rate Test	
LTS-600-41	Primary Containment Inspections for ECCS Suction Strainer Debris Sources	6
LTS-700-18	Unit 1(2) Division I Battery Modified Performance Test	4
MA-AA-716-008	Foreign Material Exclusion Program	2
N/A	Special Log - Gross Lake Level	September 24, 2007
NES-EIC-20.01	Standard for Evaluation of M&TE Accuracy When Calibrating Instrument Components and Channels	1
NES-EIC-20.04	Analysis of Instrument Channel Setpoint Error and Instrument Loop Accuracy	4

REFERENCES

Number	Description or Title	Date or Revision
000428J	Completion Report for NRC Bulletin 96-03, “Potential Plugging of Emergency Core Cooling Suction Strainers by Debris in BWRs”	April 28, 2000
01ODSL-011	Operations Training - EDG and Auxiliaries	6
01OSDL 005	Operations Training - AC Distribution	7
01OSDL 006	Operations Training - DC Distribution	6
1427-DG006	RSO Setting Sheet - ITE59 Voltage Relay	May 9, 2006
21A9243CL	Purchase Specification Data Sheet Residual Heat Removal Pumps	3
344788	Evaluation of Reasonable Assurance of Safety for Loss of 0PM08J	September 24, 2003
9507738	Testing 4KV Circuit Breaker Spring Charging Motor at UV Conditions	October 10, 1995
CHRON 307384	Evaluation of Turbine Building Flooding	March 21, 1995
DBD-LS-M11	Flood Protection	B
DS-ECCS-LS-01	La Salle County Station ECCS Suction Strainer Replacement	August 21, 1997
EQ-LS079	Environmental Qualification Engineering – Motor Operated Valves: Limitorque SMB – Series	17
EQ-LS102	Environmental Qualification Engineering – Solenoid Valves: Valcor/V70900-87-8	2
L99-126	10 CFR 50.59 Evaluation	May 20, 1999
LAS AP1	4KV System Health Overview Report	June 2007
LAS AP2	480V SWGR System Health Overview Report	June 2007
LAS AP3	480V MCC System Health Overview Report	June 2007

REFERENCES

Number	Description or Title	Date or Revision
LAS DC/D1	DC Div 1 System Health Overview Report	June 2007
Letter	La Salle County Station Response to NRC Bulletin 96-03, “Potential Plugging of Emergency Core Cooling Suction Strainers by Debris in BWRs”	November 1, 1996
LSCS-FSAR	Appendix J.1, Moderate Energy Lines	Amend. 36
LU1999-032	UFSAR Change Request Form	May 26, 1999
LUCR #87	UFSAR Change Request Form	September 29, 2006
MA-LA-773-402 ATT 1	U2 Div 1 Degraded Voltage Relay Calibration	April 24, 2006
ML072140550	Safety Evaluation Input for Proposed Technical Specification Change for Ultimate Heat Sink Temperature Increase for LaSalle Units 1 and 2 (TAC NOs. MD6014 and MD6015)	August 2, 2007
ML072140844	LaSalle County Station, Units 1 and 2 – Issuance of Amendments RE: Technical Specification 3.7.3, Ultimate Heat Sink Request for Processing On An Emergency Basis (TAC NOS. MD6014 and MD6015)	August 2, 2007
MSD-97-018-01	La Salle Station ECCS Pumps Runout Flow Rates	0
N/A	EGC/AmerGen 60-Day response to NRC Generic Letter 2006-02	April 3, 2006
N/A	ComEd Letter- NRC Bulletin No. 88-04	July 11, 1988
N/A	Dresser-Rand Letter	September 21, 2007
NEDO-32686	Utility Resolution Guidance for ECCS Suction Strainer Blockage	0
NF-AB-120	Reload Licensing (BWR)	6
OG97-044-161	BWR Owners Group Response to NRC Comments and Questions Regarding NEDO-32686 Revision O, “Utility Resolution Guidance for ECCS Suction Strainer Blockage”	January 30, 1997
RS-07-069	Request for a License Amendment to Technical Specification 3.7.3, “Ultimate Heat Sink”	June 29, 2007
RS-07-112	Additional Information Supporting Request for a License Amendment to Technical Specification 3.7.3, “Ultimate Heat Sink,” and Request for Processing On An Emergency Basis	August 1, 2007
RS-07-113	Additional Information Supporting Request for Emergency License Amendment to Technical Specification 3.7.3, “Ultimate Heat Sink”	August 2, 2007
SCM-04060	Moderate Energy Pipe Break Evaluations in Diesel and Turbine/Auxiliary Buildings	April 18, 1995
SCM-04072	Moderate Energy Pipe Break Evaluations in Diesel and Turbine/Auxiliary Buildings	April 20, 1995

REFERENCES

Number	Description or Title	Date or Revision
SEAG 97-00045	La Salle ECCS Strainer Replacement Summary Results From Test Procedure TPP-VL0400-02 Performed at the Fairbanks Morse Pump Corp.	October 29, 1997
SEAG 99-000415	Independent Third Party Review of Calculations L-002051, L-001222 and L-001261 for La Salle County Station Regarding Conformance with Bulletin 96-03	March 31, 1999
Test Report 18333-83N	Seismic Vibration Testing of Various Relays	May 11, 1983
TID-E/I&C-04	Thermal Overload Heater Selection for Continuous Duty Motors	0

VENDOR DOCUMENTS

Number	Description or Title	Date or Revision
	ECCS and RCIC Sure-Flow Suction Strainers	September 25, 1997
J-0981	Efector – Operating Instructions for Model Number TR2432 Control Monitor for Temperature Sensors	1
P/N 603016	Honeywell 2020 System Calibrator Users Manual	2
QATR Manual	Chapter 12 – Control of Measuring and Test Equipment	79
J-0150	Vendor Manual - Station Batteries and Accessories	6
J-0955	SSCI Instruction/Technical Manual for Model 85-CC2000-102 Type 200 Amp Battery Chargers	000

WORK DOCUMENTS

Number	Description or Title	Date or Revision
	Unit 1 RHR-A Heat Exchanger Eddy Current Results	January 19, 2004
	Unit 2 Suppression Pool IWE Inspections During L2R11 Outage	March 11, 1007
LAS-87318	Special Testing (1) Efector TR2432 Control Monitor	January 31, 2006
LOS-DG-Q1	0 DG Cooling Water Pump In-service Test Results	2005-2007
LOS-DG-SR5	0 DG Cooling Water System Flow Test Results	2005-2007
LOS-RH-Q1	2A RHR WS Operability and In-service Test Results	2005-2007
LTS-100-3	LLRT Performance Based Test Interval Evaluation for Component 1B21-F022A	May 9, 2006
LTS-100-3	LLRT Performance Based Test Interval	May 9, 2006

WORK DOCUMENTS

Number	Description or Title	Date or Revision
	Evaluation for Component 1B21-F022D	
LTS-200-19	NW Cubicle Area Cooler Air Side Flowrate Test Results	2005-2007
WO 00585685	Perform MA-LA-773-532 Feed to 235X and 235Y	May 5, 2004
WO 00602305	2VY016 Loop RHR Pump Cubicle A Room Temperature Loop Calibration	1
WO 00603274	Perform MA-LA-773-532 for "A" RHR Pump	March 24, 2004
WO 00607327	Integrated Division 1 ECCS Response Time Test	February 21, 2005
WO 00608850	Unit 2 125V Battery Div I Service Discharge Test	February 2, 2005
WO 00662444	LOS-PC-Q2 AA 1A: U-1 MSIV Operability and IST Inspections	March 11, 2006
WO 00719992	LLRT, 1B21-F022A, 1B21-F028A, 1B21-F067A	October 19, 2005
WO 00725449	LLRT, 1B21-F022D, 1B-21-F028D, 1B21-F067D	October 19, 2005
WO 00780445	Inspection of South End of WS Tunnel for Corbicula and Sedimentation	August 4, 2006
WO 00781092	U2 LPCS Motor Cooler Piping NDE UT	November 30, 2005
WO 00785667	CSCS Pond Sediment Deposition Check	January, 25 2007
WO 00821502	Inspect Unit 2 Primary Containment	March 14, 2007
WO 00821551	LOS-RH-R1 2A LPCI Inj Flush Att A	February 25, 2007
WO 00835785	INBD MSIV Accum Check Vlvs ASME XI In-service Insp	January 16, 2007
WO 00835807	Inspection of North End of WS Tunnel for Corbicula and Sedimentation	May 21, 2007
WO 00848774	Clean Unit 2 A CW Inlet Bay	November 11, 2006
WO 00860829	2DC23E Div 1 Battery Charger Capacity Test	February 7, 2007
WO 00860830	Inspect Div 1 Battery Charger 2DC23E	February 7, 2007
WO 00873982	U2 Div1 RHR CSCS Piping 2RH84BA-1.5 NDE UT	April 23, 2007
WO 00881422	OP NDD: LOS-RP-Q3 MSIV Scram Functional ATT 1A	March 12, 2006
WO 00906206	Replace T/C with RTD On 2TE-CW010 and 2TE-CW011	1
WO 00996699	LOS-RH-Q1 2A RHR System Att A	April 26, 2007
WO 01002445	OP LOS-RP-Q3 MSIV Scram Functional Att 1A	May 16, 2007
WO 01025016	LOS-RH-Q1 2A RHR System Att A	May 25, 2007
WO 01028294	125VDC Div 1 Battery Checks	July 24, 2007
WO 01033662	LOS-RH-M1 U2 A RHR & WS Pumps Att A	June 25, 2007
WO 01042329	LOS-RH-M1 U2 A RHR & WS Pumps Att A	August 23, 2007
WO 01053131	125VDC Div 1 Battery/Breaker Checks	August 10, 2007
WO 744351	Inspect U-2 Div 1 125VDC Battery per LES-DC-101A	December 29, 2005
WO 930043713 01	Change High Voltage Tap Terminals	December 8, 1994

LIST OF ACRONYMS USED

°F	degrees Fahrenheit
AC	Alternating Current
ACB	Air Circuit Breaker
ADAMS	Agencywide Documents Access and Management System
AEER	Auxiliary Electrical Equipment Room
ASME	American Society of Mechanical Engineers
C&I	Control and Instrumentation
CDBI	Component Design Bases Inspection
CFR	Code of Federal Regulations
CW	Circulating Water
DC	Direct Current
DG	Diesel Generator
DGCW	Diesel Generator Cooling Water
DRS	Division of Reactor Safety
GL	Generic Letter
HPCS	High Pressure Core Spray
HVAC	Heating, Ventilation and Air Conditioning
IMC	Inspection Manual Chapter
IN	Information Notice
IR	Inspection Report or Issue Report
M&TE	Measurement and Test Equipment
MCC	Motor Control Center
MOV	Motor Operated Valve
NCV	Non-Cited Violation
NPSH	Net Positive Suction Head
NRC	U. S. Nuclear Regulatory Commission
P&ID	Piping and Instrumentation Diagram
PARS	Publicly Available Records System
PRA	Probabilistic Risk Assessment
RBCCW	Reactor Building Closed Cooling Water
RHR	Residual Heat Removal
RHRSW	Residual Heat Removal Service Water
RTD	Resistance Temperature Detector
SDP	Significance Determination Process
T/C	Thermocouple
TS	Technical Specifications
UFSAR	Updated Final Safety Analysis Report
UHS	Ultimate Heat Sink
WO	Work Order